University of Alberta

THE APPLICATION OF THE LUUS-JAAKOLA DIRECT SEARCH METHOD TO THE OPTIMIZATION OF A HYBRID RENEWABLE ENERGY SYSTEM

by

Bernhard Michael Jatzeck

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A thesis submitted to the Faculty of Graduate Studies and
Research in partial fulfilment of the requirements for the
degree of Doctor of Philosophy

Department of Electrical and Computer Engineering

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ABSTRACT

The application of the Luus-Jaakola direct search method to the optimization of stand-alone hybrid energy systems consisting of wind turbine generators (WTG's), photovoltaic (PV) modules, batteries, and an auxiliary generator was examined. The loads for these systems were for agricultural applications, with the optimization conducted on the basis of minimum capital, operating, and maintenance costs. Five systems were considered: two near Edmonton, Alberta, and one each near Lethbridge, Alberta, Victoria, British Columbia, and Delta, British Columbia. The optimization algorithm used hourly data for the load demand, WTG output power/area, and PV module output power. These hourly data were in two sets: seasonal (summer and winter values separated) and total (summer and winter values combined). The costs for the WTG's, PV modules, batteries, and auxiliary generator fuel were full market values. To examine the effects of price discounts or tax incentives, these values were lowered to 25% of the full costs for the energy sources and two-thirds of the full cost for agricultural fuel. Annual costs for a renewable energy system depended upon the load, location, component costs, and which data set (seasonal or total) was used. For one Edmonton load, the cost for a renewable energy system consisting of 27.01 m^2 of WTG area, 14 PV modules, and

18 batteries (full price, total data set) was $6873/year. For Lethbridge, a system with 22.85 m^2 of WTG area, 47 PV modules, and 5 batteries (reduced prices, seasonal data set) cost $2913/year. The performance of renewable energy systems based on the obtained results was tested in a simulation using load and weather data for selected days. Test results for one Edmonton load showed that the simulations for most of the systems examined ran for at least 17 hours per day before failing due to either an excessive load on the auxiliary generator or a battery constraint being violated. Additional testing indicated that increasing the generator capacity and reducing the maximum allowed battery charge current during the time of the day at which these failures occurred allowed the simulation to successfully operate.

PREFACE

The work conducted for this investigation was for academic research purposes only. The results and conclusions are those of the author only and should not be construed as engineering advice. Questions concerning this thesis should be directed to the author.

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LIST OF SYMBOLS, NOMENCLATURE, AND ABBREVIATIONS

A = albedo
= member of stochastic programming problem σ-field
$\mathbf{A}$ = constraint coefficients
A_W = wind turbine generator rotor area (m^2)
$A_{W_{MAX}}$ = maximum wind turbine generator rotor area (m^2)
$A_{W_{MIN}}$ = minimum wind turbine generator rotor area (m^2)
$\mathbf{b}$ = constraint limits
b_F = no-load auxiliary generator fuel consumption rate (L/hr)
$\mathbf{c}$ = objective function coefficients
c_A = annualized capital cost factor
C_B = annualized battery cost ($/battery)
c_B = battery cost ($/A-hr/battery)
C_F = annualized fuel cost ($/L)
c_F = fuel cost ($/L)
C_G = annualized auxiliary generator cost ($/W)
c_G = auxiliary generator cost ($/W)
C_I = annualized inverter cost ($/W)
c_I = inverter cost ($/W)
C_{MG} = annualized auxiliary generator maintenance cost ($/W-hr)
c_{MO} = annualized maintenance and operating cost factor
C_{MW} = annualized wind turbine generator maintenance cost ($/W-hr)-$m^2$
C_P = wind turbine generator coefficient of performance
C_R = annualized rectifier cost ($/W)
c_R = rectifier cost ($/W)
C_S = annualized photovoltaic module cost ($/module)
c_S = photovoltaic module cost ($/module)
c_W = wind turbine cost ($/$m^2$)
C_W = annualized wind turbine cost ($/$m^2$)
d_n = n-th dynamic programming stage decision variable
E_0 = internal battery cell voltage (V)
f = auxiliary generator fuel consumption rate (L/hr)
= auxiliary generator fuel consumption rate (L/day)
f_{AC} = AC renewable energy operation flag
f_B = battery operation factor
f_C = battery charge flag

LIST OF SYMBOLS, NOMENCLATURE, AND ABBREVIATIONS (CONT'D)

f_C = battery charge flag
f_D = battery discharge flag
f_{DC} = DC renewable energy operation flag
f_i = auxiliary generator fuel consumption rate during *i*-th hour of day (L/hr)
$f(\mathbf{x})$ = objective function
$f(x_A)$ = objective function value at x_A
$f(x_B)$ = objective function value at x_B
$f[\theta x_A + (1 - \theta) x_B]$ = objective function convexity check value
$f_n(x_n)$ = *n*-th dynamic programming stage return
$f_{n-1}(x_{n-1})$ = $(n - 1)$-th stage dynamic programming return
f_{Si} = auxiliary generator fuel consumption rate during *i*-th hour of summer day (L/hr)
f_{Wi} = auxiliary generator fuel consumption rate during *i*-th hour of winter day (L/hr)
F = stochastic programming problem σ-field
$g(\mathbf{x})$ = inequality constraints for optimization
$g_i\left(x, \tilde{\xi}\right)$ = *i*-th stochastic programming problem constraint
$g_j(\mathbf{x})$ = *j*-th non-linear programming inequality constraint
$g_0\left(x, \tilde{\xi}\right)$ = stochastic programming problem objective function
G_{on} = extraterrestrial irradiance (W/m^2)
g_R = number of auxiliary generator replacements during system lifetime
G_{sc} = solar constant
$h(\mathbf{x})$ = equality constraints for optimization
$h_j(\mathbf{x})$ = *j*-th non-linear programming equality constraint
$H(\beta, \gamma)$ = total tilted surface irradiance (W/m^2)
H_b = horizontal surface beam irradiance (W/m^2)
$H_d(\beta, \gamma)$ = tilted surface diffuse irradiance (W/m^2)
H_g = global horizontal surface irradiance (W/m^2)
$H_i(\beta_i, \gamma_i)$ = irradiance on *i*-th reflecting surface (W/m^2)
$H_r(\beta, \gamma)$ = reflected irradiance (W/m^2)
i = hour index
= interest rate
= Luus-Jaakola direct search method optimization variable index
= stochastic programming constraint index
= number of reflecting surfaces
I = photovoltaic cell current (A)
= photovoltaic module current (A)
I_B = battery current (A)

LIST OF SYMBOLS, NOMENCLATURE, AND ABBREVIATIONS (CONT'D)

f_C = battery charge flag
f_D = battery discharge flag
f_{DC} = DC renewable energy operation flag
f_i = auxiliary generator fuel consumption rate during i-th hour of day (L/hr)
$f(\mathbf{x})$ = objective function
$f(x_A)$ = objective function value at x_A
$f(x_B)$ = objective function value at x_B
$f[\theta x_A + (1 - \theta) x_B]$ = objective function convexity check value
$f_n(x_n)$ = n-th dynamic programming stage return
$f_{n-1}(x_{n-1})$ = $(n - 1)$-th stage dynamic programming return
f_{Si} = auxiliary generator fuel consumption rate during i-th hour of summer day (L/hr)
f_{Wi} = auxiliary generator fuel consumption rate during i-th hour of winter day (L/hr)
F = stochastic programming problem σ-field
$g(\mathbf{x})$ = inequality constraints for optimization
$g_i\left(x, \tilde{\xi}\right)$ = i-th stochastic programming problem constraint
$g_j(\mathbf{x})$ = j-th non-linear programming inequality constraint
$g_0\left(x, \tilde{\xi}\right)$ = stochastic programming problem objective function
G_{on} = extraterrestrial irradiance (W/m^2)
g_R = number of auxiliary generator replacements during system lifetime
G_{sc} = solar constant
$h(\mathbf{x})$ = equality constraints for optimization
$h_j(\mathbf{x})$ = j-th non-linear programming equality constraint
$H(\beta, \gamma)$ = total tilted surface irradiance (W/m^2)
H_b = horizontal surface beam irradiance (W/m^2)
$H_d(\beta, \gamma)$ = tilted surface diffuse irradiance (W/m^2)
H_g = global horizontal surface irradiance (W/m^2)
$H_i(\beta_i, \gamma_i)$ = irradiance on i-th reflecting surface (W/m^2)
$H_r(\beta, \gamma)$ = reflected irradiance (W/m^2)
i = hour index
= interest rate
= Luus-Jaakola direct search method optimization variable index
= stochastic programming constraint index
= number of reflecting surfaces
I = photovoltaic cell current (A)
= photovoltaic module current (A)
I_B = battery current (A)

LIST OF SYMBOLS, NOMENCLATURE, AND ABBREVIATIONS (CONT'D)

I_{B_t} = battery current at time t (V)

I_D = diode saturation current (A)

i_I = inflation rate

I_L = light-generated photovoltaic cell current (A)

I_{REF} = photovoltaic cell reference current (A)

= photovoltaic module reference current (A)

I_{MP} = photovoltaic cell maximum power point current (A)

= photovoltaic module maximum power point current (A)

I_{SC} = photovoltaic cell short-circuit current (A)

= photovoltaic module short-circuit current (A)

$I_{SC_{REF}}$ = photovoltaic cell reference short-circuit current (A)

= photovoltaic module reference short-circuit current (A)

j = non-linear programming constraint index

= Luus-Jaakola direct search method index

k = temperature insolation change coefficient (°C/(W/m^2))

K = battery cell polarization coefficient (Ω)

$L(\mathbf{x}, \omega)$ = Lagrangian function

m = number of non-linear programming constraints

= number of stochastic programming constraints

m_F = auxiliary generator fuel consumption rate per unit power ((L/hr)/W)

n = dynamic programming stage number

= number of day of year (January 1 = 1, February 1 = 32…)

= number of time intervals since start of process

= system lifetime (yr)

n_P = number of optimization passes

N_B = number of batteries

$N_{B_{MAX}}$ = maximum number of batteries

$N_{B_{MIN}}$ = minimum number of batteries

n_{GR} = auxiliary generator replacement time (yr)

n_P = number of optimization passes for battery

n_R = remaining lifetime for auxiliary generator at end of system life (yr)

N_S = number of photovoltaic modules

$N_{S_{MAX}}$ = maximum number of photovoltaic modules

LIST OF SYMBOLS, NOMENCLATURE, AND ABBREVIATIONS (CONT'D)

$N_{S_{MIN}}$ = minimum number of photovoltaic modules
p = total number of non-linear programming constraints
P = stochastic programming problem set function
$P[f(\mathbf{x}), g(\mathbf{x}), h(\mathbf{x})]$ = penalty function
P_B = battery power (W)
P_{B_t} = battery power at time t (W)
P_G = auxiliary generator power (W)
$P_{G_{MAX}}$ = maximum auxiliary generator capacity (W)
$P_{G_{MIN}}$ = minimum auxiliary generator capacity (W)
P_{G_i} = auxiliary generator output power during i-th hour of day (W)
P_{G_t} = auxiliary generator output power at time t (W)
P_{GS_i} = auxiliary generator output power during i-th hour of summer day (W)
P_{GW_i} = auxiliary generator output power during i-th hour of winter day (W)
P_G^* = required auxiliary generator capacity (W)
$P_{G_t}^*$ = required auxiliary generator output power at time t (W)
$P_{G_{t-1}}^*$ = required auxiliary generator output power at time $t - 1$ (W)
P_G' = reference auxiliary generator capacity (W)
P_I = inverter capacity (W)
P_{I_t} = inverter capacity at time t (W)
$P_{I_t}^*$ = required inverter capacity at time t (W)
$P_{I_{t-1}}^*$ = required inverter capacity at time $t - 1$ (W)
P_{L_t} = load demand at time t (W)
P_R = rated wind turbine generator output power (W)
= rectifier capacity (W)
P_{R_t} = rectifier capacity at time t (W)
$P_{R_t}^*$ = required rectifier capacity at time t (W)
$P_{R_{t-1}}^*$ = required rectifier capacity at time $t - 1$ (W)
P_{S_t} = photovoltaic module output power at time t (W)
P_W = available wind turbine generator output power per unit area (W/m^2)
= instantaneous wind turbine generator output power (W)

LIST OF SYMBOLS, NOMENCLATURE, AND ABBREVIATIONS (CONT'D)

P_{W_i} = available wind turbine generator output power per unit area during i-th hour of day (W/m^2)
P_{W_t} = available wind turbine generator output power per unit area at time t (W/m^2)
P_{WS_i} = available wind turbine generator output power per unit area during i-th hour of summer day (W/m^2)
P_{WW_i} = available wind turbine generator output power per unit area during i-th hour of winter day (W/m^2)
Q = instantaneous battery charge (A-hr)
$\mathbf{Q}$ = quadratic programming coefficients
Q_F = final battery charge (A-hr)
Q_{L_t} = minimum allowed battery charge at time t (A-hr)
Q_{MAX} = maximum battery capacity (A-hr)
Q_{MIN} = minimum battery capacity (A-hr)
Q_t = battery charge at time t
Q_{t-1} = battery charge at time $t - 1$
Q_{U_t} = maximum allowed battery charge at time t (A-hr)
Q_0 = initial battery charge (A-hr)
$r_i^{(j)}$ = range for i-th Luus-Jaakola search method optimization variable during j-th iteration
$r_i^{(j-1)}$ = range for i-th Luus-Jaakola search method optimization variable during $(j - 1)$-th iteration
$r_{\Delta Q_t}$ = initial range for ΔQ_t (A-hr)
R = battery cell internal resistance (Ω)
R_n = n-th stage dynamic programming objective function
R_S = photovoltaic cell series resistance (Ω)
= photovoltaic module series resistance (Ω)
R_{SH} = photovoltaic cell shunt resistance (Ω)
S = irradiance (W/m^2)
= salvage fraction
= stochastic programming sample space
S_B = battery switch
S_{BDL} = battery/dump load branch switch
S_{DL} = dump load switch
S_G = auxiliary generator switch
S_I = inverter switch
S_L = load switch
S_{PV} = photovoltaic module switch
S_R = rectifier switch

LIST OF SYMBOLS, NOMENCLATURE, AND ABBREVIATIONS (CONT'D)

S_{REF} = reference irradiance (W/m^2)
S_T = transformer switch
S_{WTG} = wind turbine generator switch
T = photovoltaic cell temperature (°C)
= photovoltaic module temperature (°C)
T_A = ambient temperature (°C)
t_{G_i} = auxiliary generator operating time during i-th hour of day (hr)
t_{GS_i} = auxiliary generator operating time during i-th hour of summer day (hr)
t_{GW_i} = auxiliary generator operating time during i-th hour of winter day (hr)
T_{REF} = photovoltaic cell or module reference temperature (°C)
T_{r_b} = beam radiation atmospheric transmittance
v = wind speed (m/s, km/hr)
V = photovoltaic cell voltage (V)
= photovoltaic module voltage (V)
V_B = battery voltage (V)
V_{B_C} = battery cell voltage (V)
V_{B_t} = battery cell voltage at time t (V)
v_{CI} = wind turbine generator cut-in wind speed (m/s, km/hr)
v_{CO} = wind turbine generator cut-out wind speed (m/s, km/hr)
v_R = wind turbine generator rated wind speed (m/s, km/hr)
V_{MP} = photovoltaic cell maximum power point voltage (V)
= photovoltaic module maximum power point voltage (V)
V_{OC} = photovoltaic cell open-circuit voltage (V)
= photovoltaic module open-circuit voltage (V)
V_{REF} = photovoltaic cell reference voltage (V)
= photovoltaic module reference voltage (V)
V_{OUT} = photovoltaic cell output voltage (V)
x = stochastic programming problem optimization variables
$\mathbf{x}$ = optimization variables
x_A = convexity/concavity check variable
x_B = convexity/concavity check variable
$x_i^{(j)}$ = i-th Luus-Jaakola search method optimization variable during j-th iteration

LIST OF SYMBOLS, NOMENCLATURE, AND ABBREVIATIONS (CONT'D)

$x_i^{*(j-1)}$ = initial value for i-th Luus-Jaakola search method optimization variable during $(j - 1)$-th iteration
x_n = n-th dynamic programming stage input
x_{n-1} = n-th dynamic programming stage output
x_0 = range reduction parameter
y_i = random number for i-th Luus-Jaakola search method optimization variable
α = photovoltaic current temperature change coefficient (A/°C)
β = photovoltaic voltage temperature change coefficient (V/°C)
= surface tilt angle (degrees)
β_i = surface tilt angle of i-th reflecting surface (degrees)
δ = declination (degrees)
$\delta(n_R)$ = unit impulse function
ΔP_{G_t} = increase in required auxiliary generator capacity at time t (W)
ΔP_{I_t} = increase in required inverter capacity at time t (W)
ΔP_{R_t} = increase in required rectifier capacity at time t (W)
ΔP_t = difference between load demand and combined renewable energy output powers at time t (W)
ΔQ = change in battery charge (A-hr)
ΔQ_t = change in battery charge at time t (A-hr)
Δt = time interval (hr)
ε = reduction factor for Luus-Jaakola search method optimization variable range
ϕ = latitude (degrees)
γ = surface azimuth angle (degrees) (due south 0°)
γ_i = surface azimuth angle of i-th reflecting surface (degrees) (due south 0°)
η = Luus-Jaakola search method optimization range reduction factor
η_I = inverter efficiency
η_R = rectifier efficiency
θ = convexity/concavity scalar
= incidence angle (radians)
θ_i = incidence angle of reflected irradiance from i-th reflecting surface with respect to tilted surface (radians)

LIST OF SYMBOLS, NOMENCLATURE, AND ABBREVIATIONS (CONT'D)

θ_z = solar zenith angle (radians)
ρ = air density (kg/m^3)
ρ_R = rated air density (kg/m^3)
σ_j = Lagrangian slack variable
τ_C = allowed battery charge time (hr)
τ_D = allowed battery discharge time (hr)
ω = hour angle with respect to local standard noon (degrees) (mornings negative)
= Lagrangian multiplier
ω_i = solid angle of *i*-th reflecting surface with respect to tilted surface (steradians)
$\underset{\sim}{\omega}_j$ = *j*-th Lagrangian multiplier
ξ = stochastic programming problem random vector

LJ = Luus-Jaakola
LP = linear programming
MILP = mixed-integer linear programming
MINLP = mixed-integer non-linear programming
NLP = non-linear programming
PV = photovoltaic
SOC = state of charge
WTG = wind turbine generator

1.0. INTRODUCTION

In remote human habitations, a reliable and economical source of electrical power is necessary for the operation of essential services, such as communications and medical facilities. Examples of such locations are communities in the Canadian arctic and farms in the vicinity of the Alaska Highway in northern British Columbia. Often, these locations are not served by an existing electrical utility grid, necessitating either the installation of a power line connected to the nearest grid or the use of an independent power source, such as a diesel generator.

The installation of a new distribution line from an existing utility grid can cost up to $15,000 - $20,000 per kilometre [1]. In addition to the installation costs, other factors have to be considered as well, such as compensation should the line cross a landowner's property, and responsibility for maintaining accessibility to the line through the removal of vegetation.

In such cases, an independent power source can be a feasible alternative. Often, a diesel-fuelled electrical generator (or genset) is used, but, since prolonged operation of these units may be necessary, the associated operating and maintenance expenses can also be considerable. In addition, there may be concerns with regards to exhaust emissions and noise.

One possibility for an independent power source is a system based on renewable energy sources, two of which are wind and sunlight. Additional power can be provided by a rechargeable battery bank and an auxiliary diesel generator.

The investigation conducted for this thesis considered the optimization of such a system on the basis of cost. The end uses for this system restricted to either small farms or agricultural facilities as load demand data was available for them.

2.0. OBJECTIVES

The objectives of this investigation were to:

- obtain meteorological and farm load demand data for several locations in western Canada,
- acquire models for the renewable energy sources,
- convert the meteorological data into a form which can be utilized by the renewable energy source models,

- obtain output power data for the renewable energy sources based on the meteorological data and the models used,
- develop an optimization algorithm using the renewable energy source output power data and load demand data, and
- apply the algorithm and determine the optimum system configurations, with the optimum based on cost and commercially-available hardware, subject to applicable constraints and limits.

3.0. CONCLUSIONS

The conclusions of this investigation are:

- the formulated algorithm can be applied to the optimization of a stand-alone hybrid renewable energy system,
- optimization runs using seasonal data yield different results than those using summer and winter data combined, with the associated costs being higher due to higher load demands and less sunlight during winter,
- hybrid energy systems for loads with magnitudes of at least 2 MW can be optimized using this method, and
- upper limits on the wind turbine generator (WTG) capacity and lower limits on the number of photovoltaic (PV) modules and batteries are major factors in the optimization.

4.0. RECOMMENDATIONS

Based on the results of this investigation, the following is recommended:

- further development of this optimization method should continue, possibly including increased battery capacity, variable inclination angle, and battery charge control,
- the effects of varying the design parameters, such as component operating characteristics, should be investigated,
- the economic model should be developed further to include more detailed maintenance costs and variable interest rates,
- the application of this method to larger systems should be investigated further, particularly with respect to scaling, and

- the optimization of renewable energy systems for other loads at different locations should be investigated.

5.0. DISCUSSION

5.1. Background

The design and operation of power systems utilizing renewable energy sources has been examined for many years by a number of investigators [2] - [36]. In particular, systems consisting of combinations of:

- photovoltaic (PV) modules,
- wind turbine generators (WTG),
- batteries, and
- auxiliary generators (either gasoline- or diesel-fuelled)

were studied in detail [4] - [36].

Of particular concern is the ability of the system to generate sufficient power to meet a given load demand, due to the variability of the energy available from sunlight and wind at a given location.

The combination of energy sources is also of interest to not only ensure that sufficient power is available, but also to allow the installation and operation of the system at minimum total capital, operating, and maintenance cost. Power in excess of the load demand can often go unused, resulting in large capital expenditures for under-utilized generating capacity. Insufficient capacity results in the load demand not always being met. Also, advantages to using such power systems (compared to conventional sources, such as utility grids) must exist. These advantages can be economic (such as being lower in cost compared with other alternatives) or environmental (such as reducing pollution).

The probability that sufficient power will be available for a given load has also been examined, such as in the investigations described in [2] and [3]. Given:

- a specified time period,
- a set of available generators, and
- a forecast load demand,

the energy generation can be simulated [2]. This can be optimized over a period of several years (such as suggested in [3]) or can be used for short-term scheduling of available generators in an existing system [4] - [6].

Hybrid systems consisting of selected combinations of energy sources have also been investigated. Examples of such systems are the following:

- PV and batteries only [7] - [10],
- WTG and diesel generator [4], [12],
- PV, WTG, and diesel generator [5],
- PV and WTG [13], [14],
- PV, batteries, and diesel generator [15] - [17],
- PV, WTG, and batteries [18] - [24], and
- PV, WTG, batteries, and diesel generator [6], [25] - [32].

In addition, some investigators considered renewable energy systems which were connected to power utility grids, examples of which were given in [33] - [36], with [31] examining such a case for comparison.

Several of the aforementioned publications considered the optimization of the systems examined. Of the ones using all four energy sources for stand-alone systems, only [26], and [30] - [32] are concerned with it.

Several optimization methods were utilized in [7] - [36], such as:

- combined methods (such as linear and dynamic programming or dynamic programming and augmented Lagrangian relaxation) [7], [33],
- incremental variation of energy source capacities [13], [18],
- linear and mixed-integer linear programming [15], [23], [30], [32],
- worst-case conditions [19],
- genetic algorithms [26], and

- multi-objective methods [35], [36].

The investigation conducted for this thesis examined the optimization of a number of stand-alone hybrid renewable energy systems. These systems consisted of photovoltaic modules, wind turbine generators, a set of rechargeable batteries, and an auxiliary diesel-fuelled generator. The loads considered were restricted to agricultural facilities at several locations in Alberta and British Columbia, as load demand data were available for them.

The work performed for this investigation included the modelling of the renewable energy sources, analysis of the meteorological and load demand data, the formulation of an optimization method, and an examination of the performance of the systems based upon the results which were obtained.

5.2. Hybrid Energy System

5.2.1. Hybrid Energy System Configuration

5.2.1.1. Symbols

S_B = battery switch
S_{BDL} = battery/dump load branch switch
S_{DL} = dump load switch
S_G = auxiliary generator switch
S_L = load switch
S_{PV} = photovoltaic module switch
S_R = rectifier switch
S_T = transformer switch
S_{WTG} = wind turbine generator switch

5.2.1.2. Description

The hybrid energy system examined for this investigation consisted of the following:

- photovoltaic modules,
- wind turbine generators,
- rechargeable batteries,
- an auxiliary generator,
- a dump load, and
- appropriate power conditioning devices, such as a rectifier and an inverter.

A typical configuration is shown in Figure 5.2-1.

5.2.1.2. Energy Source Dispatch

The energy sources for a system such as the one in Figure 5.2-1 can be dispatched in a number of ways, such as the following:

- the load demand is to be primarily met by PV modules and/or the WTG's (given appropriate weather conditions),
- any energy in excess of the load demand is to be used for recharging the batteries,
- any excess energy remaining is to be dissipated through the dump load, and
- if the combined output of the PV modules and WTG's is less than the load demand, the deficit to be met by the batteries (if sufficient charge is available) and auxiliary generator (to be used if the combined output of PV modules, WTG, and batteries is insufficient to meet the instantaneous load demand).

An adequate supply of fuel for the auxiliary generator is assumed to be available at all times.

In order the renewable energy system to operate, the switches in Figure 5.2-1 must be co-ordinated. This is allows the energy sources to be dispatched to either meet the load demand or charge the batteries, as well as disconnect individual energy sources from the system when they are not in use. In addition, the switches can be opened to isolate sections of the system for maintenance purposes.

The switch settings and the conditions under which they occur are presented in Table 5.2-1. It should be noted that S_{BDL}, S_T, and S_L are normally closed and would be opened during periods of maintenance or for safety reasons.

5.2.2. Photovoltaic Module Operation

5.2.2.1. Symbols

I = photovoltaic cell current (A)
= photovoltaic module current (A)
I_D = diode saturation current (A)
I_L = light-generated photovoltaic cell current (A)
I_{MP} = photovoltaic cell maximum power point current (A)
= photovoltaic module maximum power point current (A)
I_{REF} = photovoltaic cell reference current (A)

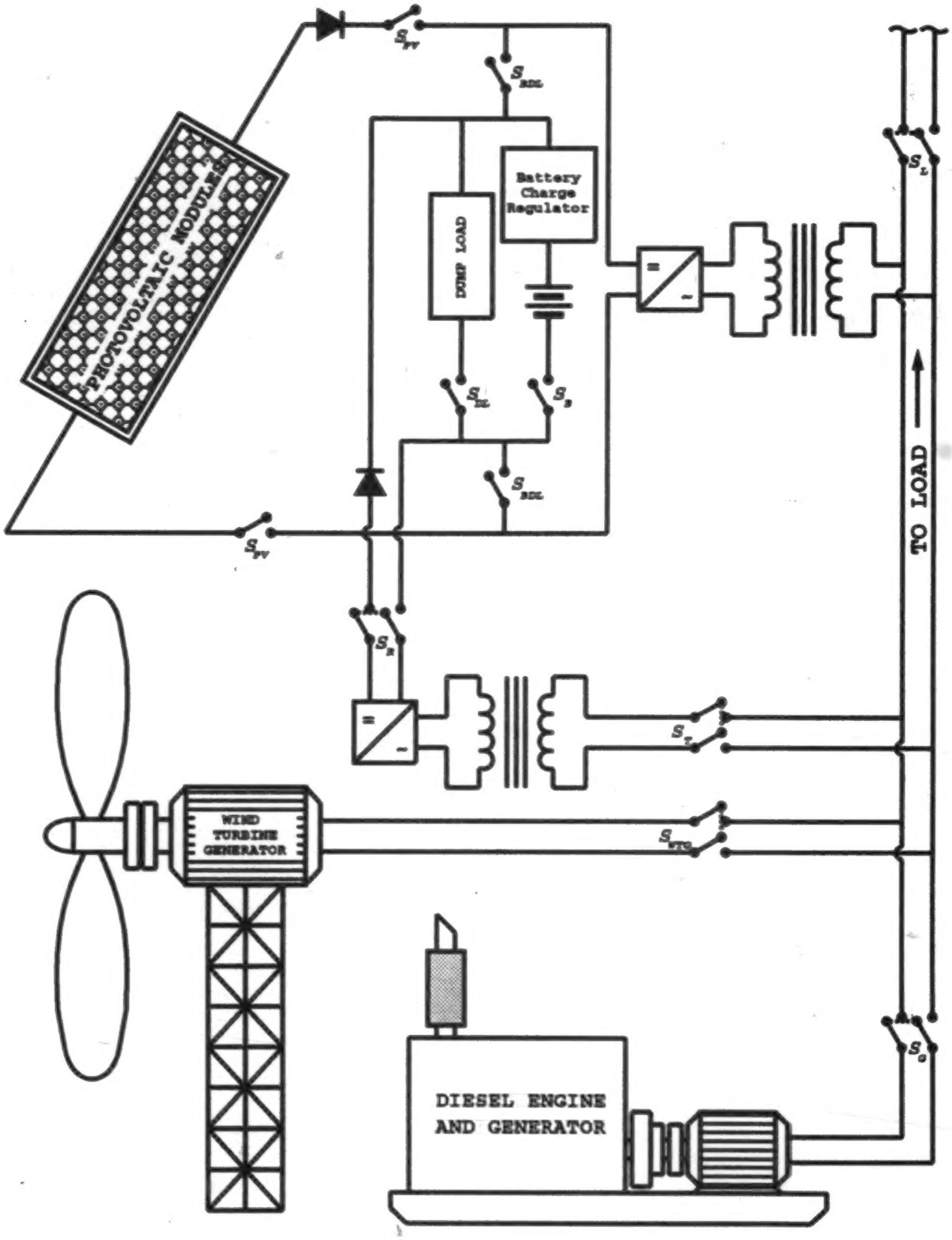

S_{PV}
S_{BDL}
Battery Charge Regulator
DUMP LOAD
PHOTOVOLTAIC MODULES
S_{DL}
S_B
S_{BDL}
S_{PV}
S_L
TO LOAD
S_R
S_T
WIND TURBINE GENERATOR
S_{WTG}
S_G
DIESEL ENGINE AND GENERATOR

Fig. 5.2-1. Typical Hybrid Energy System

Table 5.2-1. Renewable Energy System Switch Settings

S_{PV}	S_{BDL}	S_B	S_{DL}	S_{WTG}	S_G	S_R	S_T	S_L	Mode
0	*	0	0	0	1	0	*	*	Auxiliary generator meets load demand
0	*	0	0	1	0	0	*	*	WTG meets load demand
0	*	0	0	1	1	0	*	*	WTG and auxiliary generator meet load demand
0	*	0	1	1	0	0	*	*	WTG meets load demand, excess to dump load
0	*	0	1	1	1	0	*	*	WTG and auxiliary generator meet load demand, excess WTG output power to dump load
0	*	1	0	0	0	0	*	*	Batteries meet load demand
0	*	1	0	0	1	0	*	*	Batteries and auxiliary generator meet load demand
0	*	1	0	0	1	1	*	*	Auxiliary generator meets load demand, batteries charged
0	*	1	0	1	0	0	*	*	Batteries and WTG meet load demand
0	*	1	0	1	0	1	*	*	WTG meets load demand, batteries charged
0	*	1	0	1	1	0	*	*	Batteries, WTG, and auxiliary generator meet load demand

0 = open/1 = closed/* = normally closed

Table 5.2-1. Renewable Energy System Switch Settings (Cont'd)

S_{PV}	S_{BDL}	S_B	S_{DL}	S_{WTG}	S_G	S_R	S_T	S_L	Mode
0	*	1	0	1	1	1	*	*	WTG and auxiliary generator meet load demand, batteries charged
0	*	1	1	1	0	1	*	*	WTG meets load demand, batteries charged, excess WTG output power to dump load
0	*	1	1	1	1	1	*	*	WTG and auxiliary generator meet load demand, batteries charged, excess WTG output power to dump load
1	*	0	0	0	0	0	*	*	PV modules meet load demand
1	*	0	0	0	1	0	*	*	PV modules and auxiliary generator meet load demand
1	*	0	0	1	0	0	*	*	PV modules and WTG meet load demand
1	*	0	0	1	1	0	*	*	PV modules, WTG, and auxiliary generator meet load demand
1	*	0	1	0	0	0	*	*	PV modules meet load demand, excess output power to dump load
1	*	0	1	0	1	0	*	*	PV modules and auxiliary generator meet load demand, excess PV module power to dump load

0 = open/1 = closed/* = normally closed

Table 5.2-1. Renewable Energy System Switch Settings (Cont'd)

S_{PV}	S_{BDL}	S_B	S_{DL}	S_{WTG}	S_G	S_R	S_T	S_L	Mode
1	*	0	1	1	0	0	*	*	PV modules and WTG meet load demand, excess PV module and/or WTG output power to dump load
1	*	0	1	1	1	0	*	*	PV modules, WTG, and auxiliary meet load demand, excess PV module and/or WTG output power to dump load
1	*	1	0	0	0	0	*	*	PV modules and batteries meet load demand
1	*	1	0	0	1	0	*	*	PV modules, batteries, and auxiliary generator meet load demand
1	*	1	0	0	1	1	*	*	PV modules and auxiliary generator meet load demand, auxiliary generator charges batteries
1	*	1	0	1	0	0	*	*	PV modules, WTG, and batteries meet load demand
1	*	1	0	1	0	1	*	*	PV modules and WTG meet load demand, WTG charges batteries
1	*	1	0	1	1	0	*	*	PV modules, batteries, WTG, and auxiliary generator meet load demand
1	*	1	0	1	1	1	*	*	PV modules, WTG, and auxiliary generator meet load demand, WTG and/or auxiliary generator charge batteries

0 = open/1 = closed/* = normally closed

Table 5.2-1. Renewable Energy System Switch Settings (Cont'd)

S_{PV}	S_{BDL}	S_B	S_{DL}	S_{WTG}	S_G	S_R	S_T	S_L	Mode
1	*	1	1	0	0	0	*	*	PV modules meet load demand, charge batteries, excess output power to dump load
1	*	1	1	0	1	0	*	*	PV modules and auxiliary generator meet load demand, PV modules charge batteries, excess PV module output power to dump load
1	*	1	1	1	0	0	*	*	PV modules and WTG meet load demand, PV modules charge batteries, excess PV module output power to dump load
1	*	1	1	1	0	1	*	*	PV modules and WTG meet load demand, charge batteries, excess PV module and/or WTG output power to dump load
1	*	1	1	1	1	0	*	*	PV modules, WTG, and auxiliary generator meet load demand, PV modules charge batteries, excess PV module output power to dump load
1	*	1	1	1	1	1	*	*	PV modules, WTG, and auxiliary generator meet load demand, PV modules and WTG charge batteries, excess PV module and/or WTG power to dump load

0 = open/1 = closed/* = normally closed

= photovoltaic module reference current (A)
I_{sc} = photovoltaic cell short-circuit current (A)
= photovoltaic module short-circuit current (A)
$I_{SC_{REF}}$ = photovoltaic cell reference short-circuit current (A)
= photovoltaic module reference short-circuit current (A)
k = temperature insolation change coefficient (°C/(W/m²))
R_S = photovoltaic cell series resistance (Ω)
= photovoltaic module series resistance (Ω)
R_{SH} = photovoltaic cell shunt resistance (Ω)
S = irradiance (W/m^2)
S_{REF} = reference irradiance (W/m^2)
T = photovoltaic cell temperature (°C)
= photovoltaic module temperature (°C)
T_A = ambient temperature (°C)
V = photovoltaic cell voltage (V)
= photovoltaic module voltage (V)
V_{MP} = photovoltaic cell maximum power point voltage (V)
= photovoltaic module maximum power point voltage (V)
V_{OC} = photovoltaic cell open-circuit voltage (V)
= photovoltaic module open-circuit voltage (V)
V_{OUT} = photovoltaic cell output voltage (V)
V_{REF} = photovoltaic cell reference voltage (V)
= photovoltaic module reference voltage (V)
T_{REF} = photovoltaic cell or module reference temperature (°C)
α = photovoltaic current temperature change coefficient (A/°C)
β = photovoltaic voltage temperature change coefficient (V/°C)

5.2.2.2. General

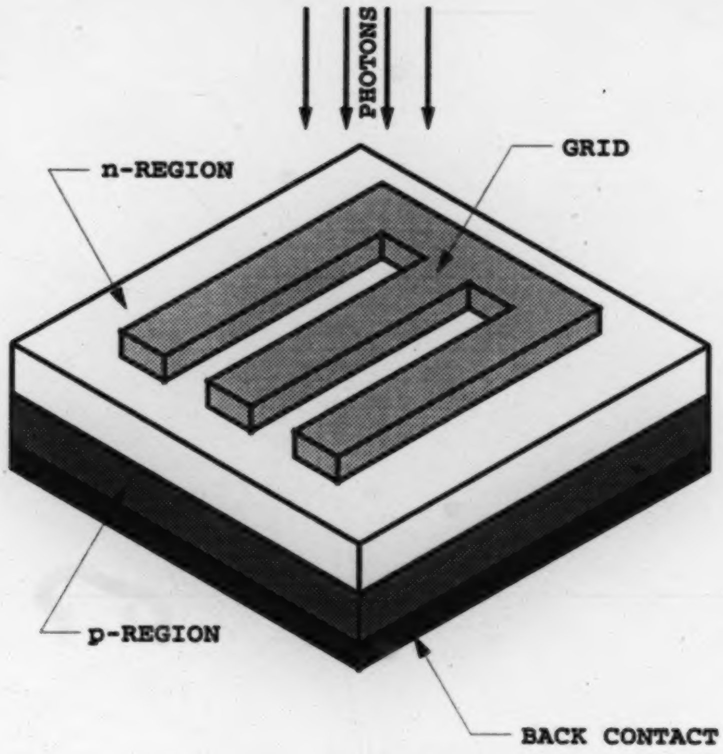
A PV cell is a semiconductor device which produces electrical power from light [37], [38]. A PV module consists of a set of cells connected together.

5.2.2.3. Basic Module Operation

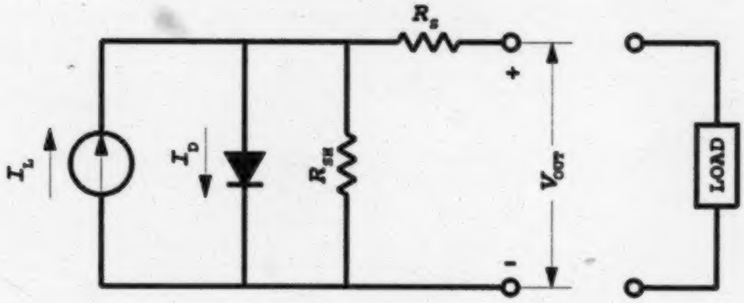
Light is absorbed by the PV cell's material, with the shorter wavelengths causing electrons to be freed from atoms inside the material's crystal lattice, giving those atoms a positive charge [39]. Electrical current is produced when the electrons and positively charged vacancies (referred to as holes) move through the material in opposite directions.

A typical PV cell layout is shown schematically in Figure 5.2-2. It consists of an n-layer (in which conduction by the electrons occurs), a p-layer (in which conduction by the holes occurs), a grid, and a back contact [39].

The electrons and holes move through the material at random and either re-combine or eventually reach the region near the


PHOTONS
GRID
n-REGION
p-REGION
BACK CONTACT

PV Cell Layout


R_S
+
I_L
I_D
R_{SH}
V_{OUT}
LOAD
-

PV Cell Schematic

Figure 5.2-2. Photovoltaic Cell Operation
(based on [37] - [39])

interface between the n- and p-layers (p-n junction). Holes in the n-layer move across the junction into the p-layer, while the electrons in the p-layer move into the n-layer. An external circuit connected to the grid and back contact allow current to flow.

Electrons move from the n-layer into the p-layer to fill the holes that are available, which creates a depletion region near the p-n junction. This region grows until a barrier develops, with conditions in the affected areas of each layer not conducive to current flow. This results in a balance between the attraction for the electrons from the p-layer holes and the barrier resulting from the movement of the holes and electrons across the p-n junction.

The flow of electrons from the n-layer to the p-layer, together with the reverse movement of the holes, results in an imbalance. The n-layer loses some valence electrons, giving the material a positive charge, while the p-layer acquires of those electrons, which gives the material a negative charge. This creates a small voltage, known as a barrier potential, across the p-n junction. This voltage prevents further movement of electrons from the n-layer to the p-layer, sweeping all of the holes and free electrons out of the depletion region.

Figure 5.2-2 also shows a schematic representation of a PV cell. Photons absorbed by the cell's material produce the light-generated current. The p-n junction is represented by the diode, with the saturation current flowing across the p-n junction. Imperfections in a typical PV cell are represented by the shunt resistance and the series resistance. The former represents the internal leakage resistance between the cell's terminals, while the latter represents the distributed resistance elements in the semiconductor, ohmic contacts, and the semiconductor/contact interface [38].

In an actual circuit, a PV cell acts as a constant-current source for constant illumination, producing DC power.

5.2.2.4. Effects of Environmental Conditions

The relationship between the voltage and current produced by a PV cell is given by [40]:

$$I = I_{sc}\left[1 - C_3\left(e^{C_4 V^*} - 1\right)\right], \qquad (5.2.2\text{-}1)$$

where:

$C_3 = 0.01175$,

$$C_4 = \frac{C_6}{V_{OC}^m},$$

$$C_6 = \ln\left(\frac{1 + C_3}{C_3}\right),$$

$$m = \frac{\ln\left(\frac{C_5}{C_6}\right)}{\ln\left(\frac{V_{MP}}{V_{OC}}\right)}, \text{ and}$$

$$C_5 = \ln\left[\frac{I_{SC}(1 + C_3) - I_{MP}}{C_3 I_{SC}}\right].$$

The performance of the cell is affected by changes in meteorological conditions, as follows [13], [41] - [43]:

$$\left.\begin{array}{l} I = I_{REF} + \Delta I, \text{ and} \\ V = V_{REF} + \Delta V. \end{array}\right\} \qquad (5.2.2\text{-}2)$$

with:

$$\Delta I = \alpha\left(\frac{S}{S_{REF}}\right)\Delta T + \left(\frac{S}{S_{REF}} - 1\right)I_{SC_{REF}},$$

$$\Delta V = \beta\Delta T - R_S\Delta I,$$

$$\Delta T = T - T_{REF}, \text{ and}$$

$$T = T_A + kS.$$

These expressions can also be applied to PV modules [13]. The effects of different temperatures and irradiance can be seen in Figure 5.2-3, which is based on data for an actual PV module [44]. The values for α, β and k for the module were estimated using both manufacturer data and the previous expressions. The value for R_S was determined using the method in [45] and data in [44].

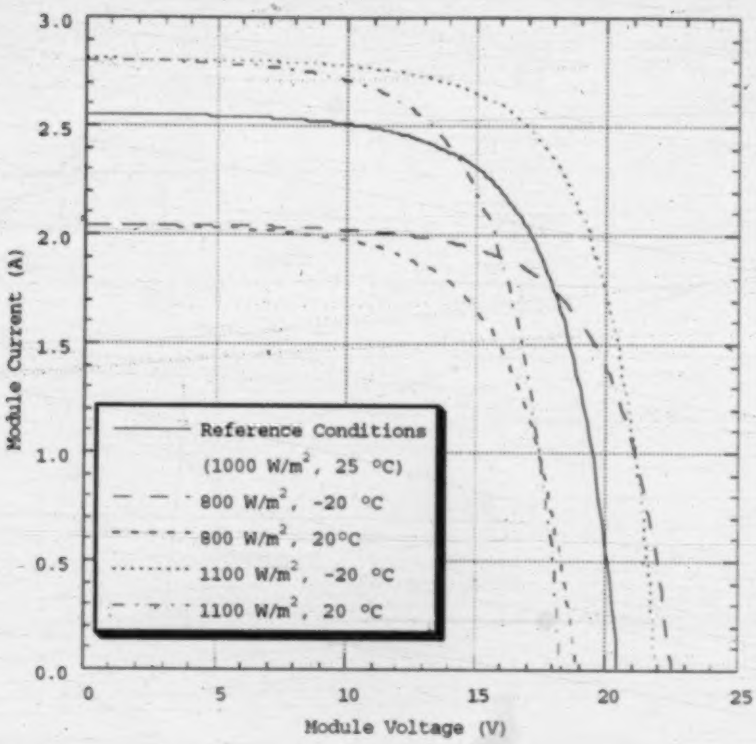


Figure 5.2-3. Photovoltaic Module Performance for Various Environmental Conditions (based on data in [44])

5.2.3. Wind Turbine Generator

5.2.3.1. Symbols

A_W = wind turbine generator rotor area (m^2)
C_P = wind turbine generator coefficient of performance
P_R = rated wind turbine generator output power (W)
P_W = instantaneous wind turbine generator output power (W)
v = wind speed (m/s, km/hr)
v_{CI} = wind turbine generator cut-in wind speed (m/s, km/hr)
v_{CO} = wind turbine generator cut-out wind speed (m/s, km/hr)
v_R = wind turbine generator rated wind speed (m/s, km/hr)
ρ = air density (kg/m^3)
ρ_R = rated air density (kg/m^3)

5.2.3.2. General

A wind turbine is a mechanical device by which the kinetic energy in a wind stream can be converted to either mechanical or electrical energy.

5.2.3.3. Basic Wind Turbine Operation

A basic wind turbine consists of a set of blades attached to a shaft which is allowed to rotate [46]. The cross-sections of these blades are actually airfoils, which, when air flows over them, cause lift to be generated, causing the blades to move and the shaft to rotate.

Numerous factors affect the performance of a wind turbine, such as the pitch angle (the angle between the airfoil chord line and the plane of rotation) and the angle of attack (the angle between the airfoil chord line and the direction of the airflow).

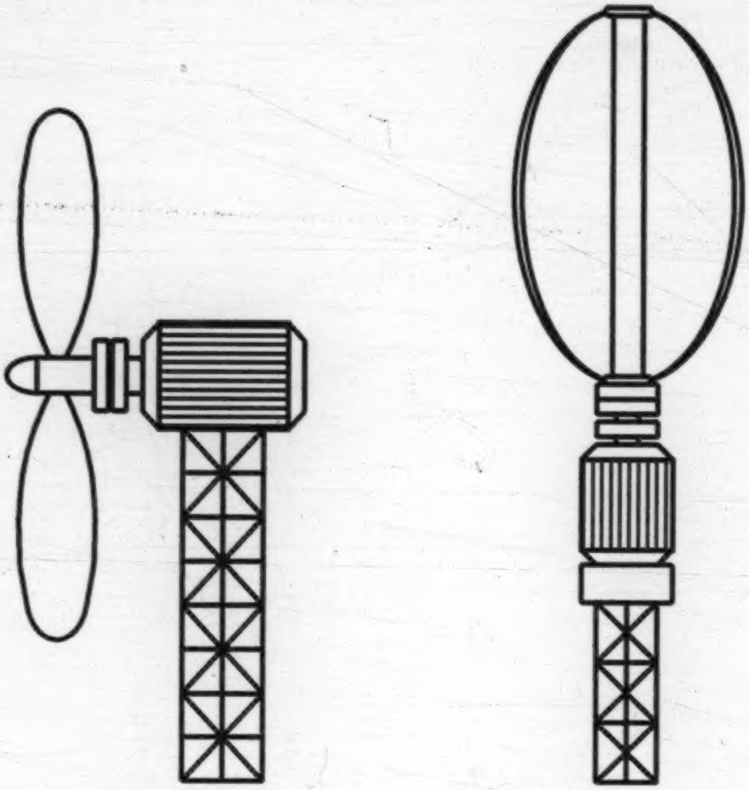
Several different configurations of wind turbine exist, with two commonly used shown in Figure 5.2-4 [47].

5.2.3.4. Wind Turbine Output Power

The output power of a wind turbine generator is described in references such as [46] and is given by:

$$P_W = \frac{1}{2} C_P \rho A_W v^3 \qquad (5.2.3\text{-}1)$$

Several different descriptions for the WTG output power curve are available, such as those given in [12], [13], [48], [49]. The one chosen for this investigation was the one given in [12]:



Horizontal-axis Vertical-axis

Figure 5.2-4. Examples of Wind Turbine Generators [47]

$$\left.\begin{aligned} P_W &= 0 && v < v_{CI} \\ &= \left(\frac{v - v_{CI}}{v_R - v_{CI}}\right)P_R && v_{CI} \le v \le v_R \\ &= P_R && v_R \le v \le v_{CO} \\ &= 0 && v_{CO} < v \end{aligned}\right\}, \qquad (5.2.3\text{-}2)$$

with:

$$P_R = \frac{1}{2} C_P \rho_R A_W v_R^3 \qquad (5.2.3\text{-}3)$$

The power curve described by this expression is shown in Figure 5.2-5. It should be noted that this power curve is an approximation. Examples of actual power curves are presented in [50], with the shape dependent upon the type of machine and operating parameters.

5.2.3.5. Electrical Generator

Synchronous generators are used for electrical power generation (see references such as [51] - [56]). Table 5.1 in [51] lists eight methods by which synchronous electrical power with constant voltage and frequency can be produced by a WTG. These methods are different combinations of:

- rotor characteristics (such as fixed or variable turbine blade pitch),

- method of mechanical power transmission between the rotor and generator, and

- types of electrical generator.

The selection of a method depends on factors such as cost and equipment required.

A synchronous generator has two major components, a rotor and a stator, which are separated by an air gap [52] - [56]. The rotor is a solid cylinder consisting of ferromagnetic material with windings on the outside surface. The stator is a hollow cylinder consisting of ferromagnetic laminated material. On the inside surface are a set of slots running along the length of the stator in which are interconnected coils.

Direct current is supplied to the rotor windings through a set of slip rings and brushes, producing a strong magnetic field. The source of the direct current commonly consists of a pilot exciter (a self-excited DC generator operating at

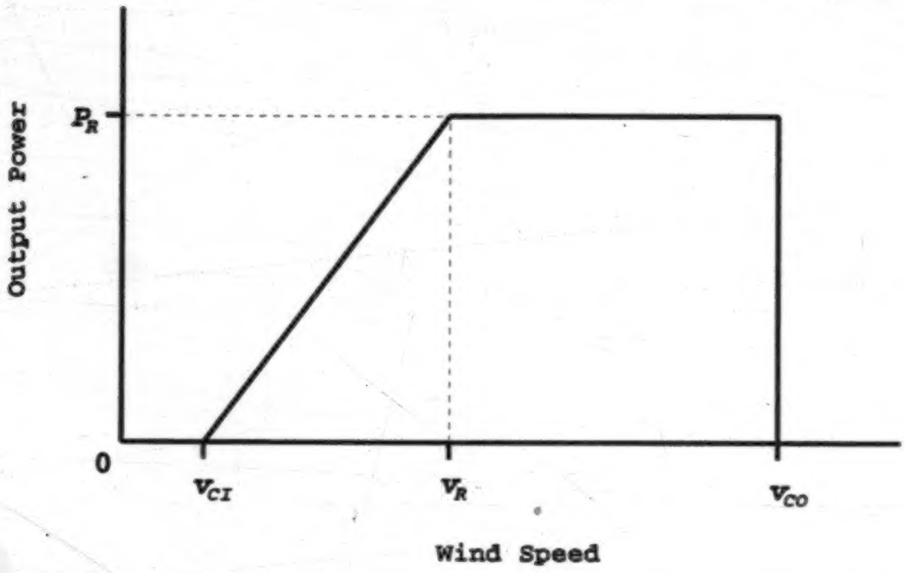


Figure 5.2-5. Wind Turbine Generator Power Curve [12]

constant voltage) and a main exciter (a separately-excited DC generator), which are driven by the synchronous generator's prime mover. Through the rotor's motion, this field is swept across the stator windings, inducing a voltage.

The frequency of the generated voltage is directly proportional to both the number of poles in the generator and the rotational speed. The rotational speed can be controlled, for example, by varying the pitch of the WTG blades, which will affect the performance of the generator (see, for example, [51], [57]).

5.2.4. Battery

5.2.4.1. Symbols

E_0 = internal battery cell voltage (V)
I_B = battery current (A)
K = battery cell polarization coefficient (Ω)
P_B = battery power (W)
R = battery cell internal resistance (Ω)
Q = instantaneous battery charge (A-hr)
Q_{MAX} = maximum battery capacity (A-hr)
V_B = battery voltage (V)
V_{B_c} = battery cell voltage (V)
η_I = inverter efficiency
η_R = rectifier efficiency

5.2.4.2. General

A battery is a device which produces electrical current by means of a chemical reaction in a set of cells [58]. A variety of different batteries exist, of which the lead-acid battery is an example.

5.2.4.3. Basic Battery Operation

In a typical electrochemical cell, two electrodes are immersed in an electrolyte with the current produced through the exchange of electrons. In general, a typical cell consists of two compartments which contain aqueous solutions of (using notation given in [59]) M^{x+} and P^{y+}, respectively. Each compartment also has an electrode, with the electrodes connected to allow current flow.

The overall cell reaction has the form (using notation given in [59], [60]):

$$M^{x+}(aq) + P^{y+}(aq) \rightarrow M^{(x+1)+}(aq) + P^{(y-1)+}(aq), \quad \ldots\ldots\ldots\ldots \quad (5.2.4\text{-}1)$$

which is a combination of two half reactions:

$$\left.\begin{array}{lcll} M^{x+}(aq) & \rightarrow & M^{(x+n)+}(aq) + ne^- & \text{(oxidation)} \\ P^{y+}(aq) + n'e^- & \rightarrow & P^{(y-n')+}(aq) & \text{(reduction)} \end{array}\right\} \quad \ldots\ldots\ldots (5.2.4\text{-}2)$$

This is shown in Figure 5.2-6.

In lead-acid batteries, negative electrodes consisting of lead sponge and positive electrodes of PbO_2 are immersed in aqueous H_2SO_4 [61].

5.2.4.4. Lead-Acid Battery Construction

Positive electrodes for lead-acid batteries are available in three different forms, depending upon manufacturing method and application [61]. For applications requiring that the battery remain stationary and have a long service life, Planté plates are used. The plates are made from cast sheets of lead upon which a thin PbO_2 layer is deposited through an electrochemical oxidation process. The effective area is increased by a series of grooves running along the length of the plate.

Negative electrodes for lead-acid batteries are almost always manufactured by using grids covered by perforated lead foil and a paste consisting of sulphuric acid and lead dioxide.

In order to prevent short-circuiting of and contact between electrodes of opposite polarity, sheets of porous insulation are inserted between the electrodes

The electrolyte density can vary between 40% (by weight) at full charge to 16% (by weight) when completely discharged [61].

5.2.4.5. Lead-Acid Battery Reactions

The overall reactions in a lead-acid battery is given by [61]:

$$Pb(s) + PbO_2(s) + 2H_2SO_4(aq) \underset{\text{Charge}}{\overset{\text{Discharge}}{\rightleftharpoons}} 2PbSO_4(s) + 2H_2O(l)\ \ldots\ldots (5.2.4\text{-}3)$$

At the positive electrode, the reactions are usually given as:

$$PbO_2(s) + 4H^+(aq) + SO_4^{2-}(aq) + 2e^- \underset{\text{Charge}}{\overset{\text{Discharge}}{\rightleftharpoons}} PbSO_4(s) + 2H_2O(l)\ \ldots (5.2.4\text{-}4)$$

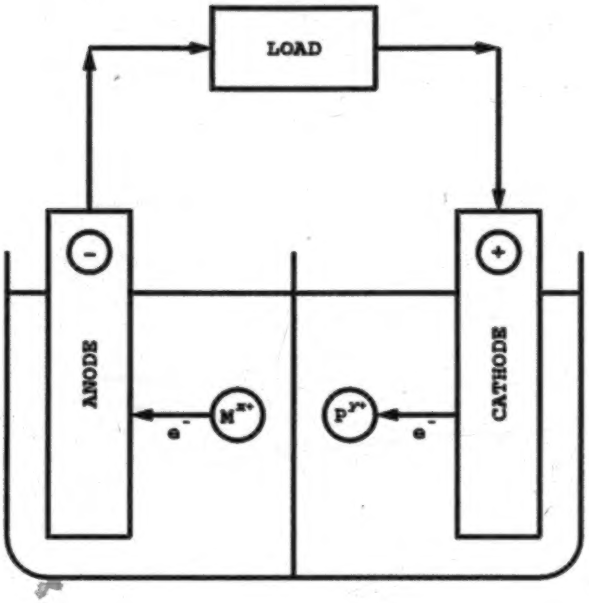

LOAD
-
+
ANODE
CATHODE
M^{x+}
P^{y+}
e^-
e^-

Figure 5.2-6. Basic Electrochemical Cell
(based on [59], [60])

while at the negative electrode, the following reactions are generally expressed as:

$$Pb(s) + SO_4^{2-}(aq) \underset{\text{Charge}}{\overset{\text{Discharge}}{\rightleftharpoons}} PbSO_4(s) + 2e^- \quad \text{(5.2.4-5)}$$

5.2.4.6. Lead-Acid Battery Operation

Figure 5.2-7 shows typical discharge and charge curves, respectively, for a lead-acid battery [61]. (For example, when the battery discharges at the *c*/10 rate, it is fully discharged in 10 hours [62].) The sudden rise in the charge curve towards the end of the charge cycle is due to the formation of hydrogen gas.

5.2.4.7. Battery Model

An expression for the battery cell voltage that has been used in an optimization method is given in [63]:

$$\left.\begin{aligned} V_{B_c} &= E_0 + \left[R + K\left(\frac{Q_{MAX}}{Q}\right)\right]I_B \quad && \text{(discharge)} \\ &= E_0 + \left[R + K\left(\frac{Q_{MAX}}{Q_{MAX} - Q}\right)\right]I_B \quad && \text{(charge)} \end{aligned}\right\}, \quad \text{(5.2.4-6)}$$

and is based on [64].

The power for a battery consisting of a set of cells is given by:

$$P_B = V_B I_B \quad \text{(5.2.4-7)}$$

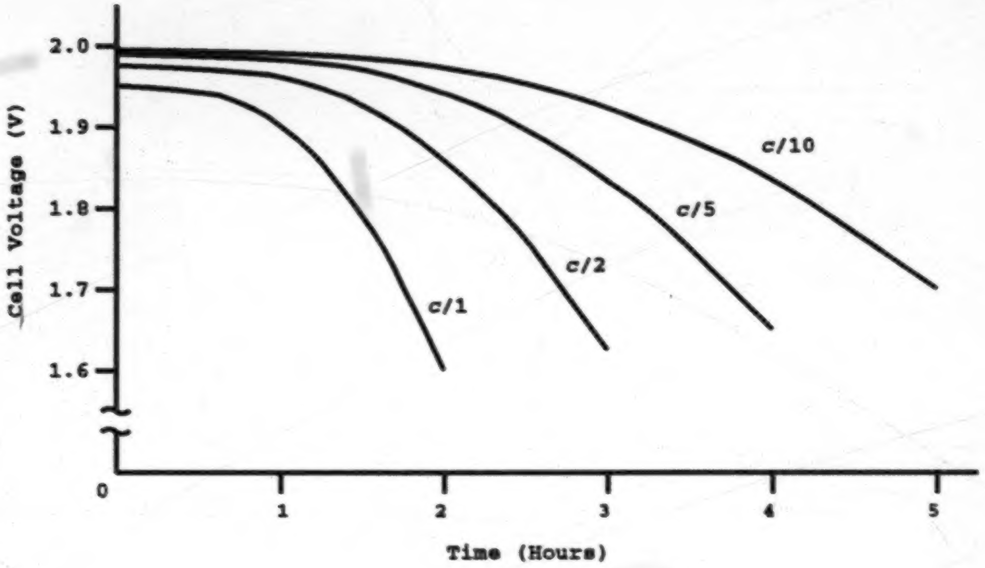
5.2.5. Auxiliary Generator

5.2.5.1. Symbols

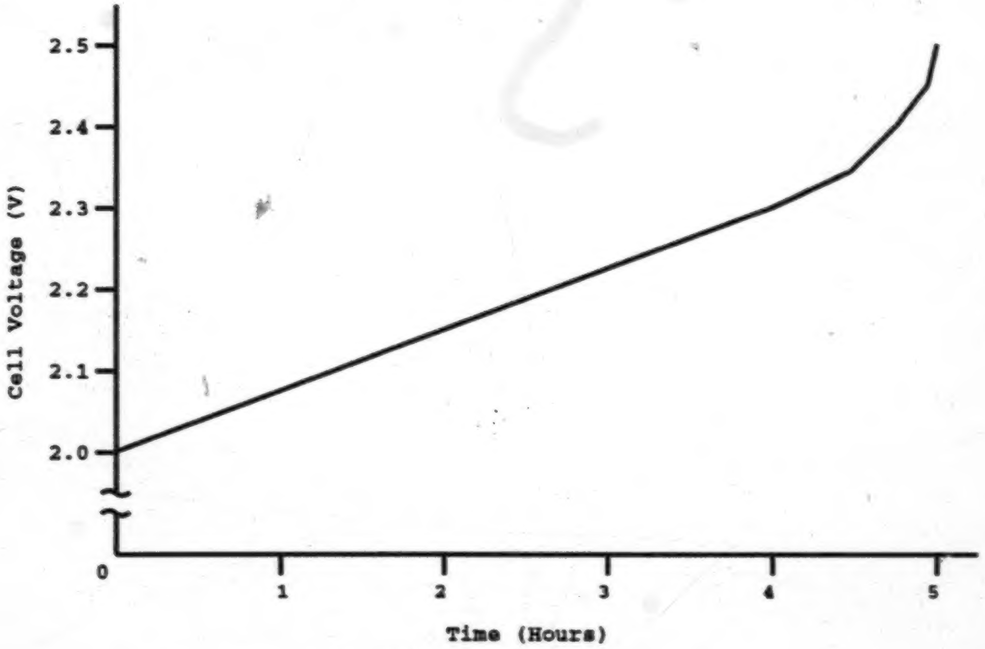
b_F = no-load auxiliary generator fuel consumption rate (L/hr)
f = auxiliary generator fuel consumption rate (L/hr)
m_F = auxiliary generator fuel consumption rate per unit power ((L/hr)/W)
P_G = auxiliary generator power (W)

5.2.5.2. General

The primary application of the auxiliary generator is to provide power to the system load if the output power from the renewable sources would be insufficient to meet the load demand. In addition, the generator could also be used to charge the batteries if no power from the renewable energy



Discharge



Charge (c/10)

Figure 5.2-7. Typical Battery Curves (based on [61])

sources was available to do so.

Electrical generators (or gensets) driven by diesel engines are often used for this purpose [65].

5.2.5.3. Diesel Engine Operation

The operation of a genset is dependent upon the performance of the driver.

The thermodynamic cycle for a diesel engine can be described by means of an air-standard cycle, which is shown in Figure 5.2-8 [66], [67]. The air-standard diesel cycle is as follows:

- compression,
- heat input at constant pressure (corresponding to combustion),
- expansion, and
- heat rejection at constant volume (corresponding to exhaust).

Actual diesel engines can have either two-stroke or four-stroke cycles.

In a diesel engine, air is drawn into the cylinder at the start of compression. Fuel is injected into the cylinder when the piston is near top dead centre [66], [68]. The air temperature causes the fuel to vaporize, allowing it to mix with the air. The air-fuel mixture ignites, which is followed by the exhausting of the combustion products.

5.2.5.4. Diesel Fuel

The composition of the fuel used by a diesel generator depends upon the composition of the original crude oil from which it was refined, as well as the actual refining process used in its production [69]. The fuel composition has an effect on the engine's fuel consumption rate through its specific energy.

The composition also affects the low-temperature operation of a diesel generator [69]. Diesel fuel cannot be pumped freely at temperatures below the pour point and fuel filters can become clogged due to, for example, the separation of the paraffin from the fuel at temperatures below the cloud point. As a result, the fuel cannot be easily atomized prior to injection into the cylinder, which affects the ability of the engine to start during cold weather. (Reference [70] considered different methods of liquid fuel atomization for vehicle

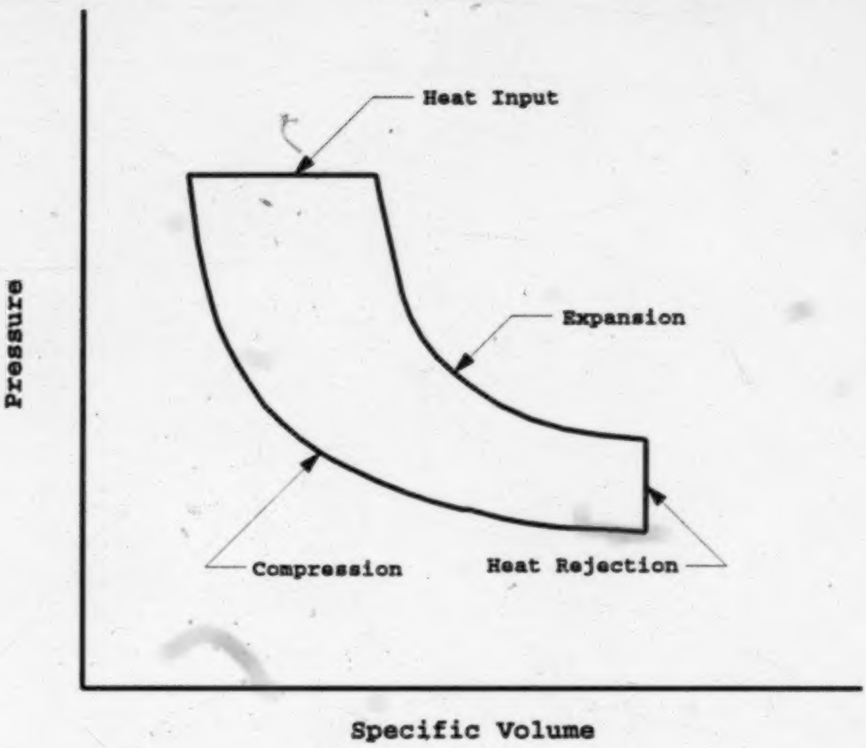

Heat Input
Expansion
Pressure
Compression
Heat Rejection
Specific Volume

Figure 5.2-8. Typical Air-standard Diesel Cycle [66], [67]

engine heating.)

5.2.5.5. Electrical Generator

Synchronous generators are used for power generation, as was described in 5.2.3.2.

Often, for an engine-driven generator set, the generator itself is directly coupled to the driver with the entire unit skid-mounted for transportation [65]. The rotational speed of the engine is determined by the frequency of the electrical power to be supplied (60 Hz in North America) and the number of poles on the generator rotor. It can range from 1200 to 3600 revolutions per minute.

5.2.5.6. Fuel Consumption Rate

Genset fuel consumption rates vary due to factors such as load and rotational speed. This variation is often displayed on a performance diagram, though these would be different for each model [71]. An example is shown in Figure 5.2-9.

For this investigation, the fuel consumption rate of an auxiliary generator is approximated by the following expression (based on information in [72]):

$$f = m_F P_G + b_F \qquad (5.2.5\text{-}1)$$

5.2.6. Load

5.2.6.1. General

Typically, an electrical load consists of the following components [73]:

- base load (constant),
- intermediate load (comprising the majority of the diurnal variation), and
- peak load (short-duration).

Electric power utilities must be able to meet the maximum load demand and also possess a significant reserve to ensure reliability. For this purpose, some power utilities estimate available generating capacity on the basis of loads exceeding peak values by a few percent [74].

The use of stored energy is known as peak shaving when it is used for generating peak power, but when it is utilized to eliminate equipment used for intermediate loads, it is known

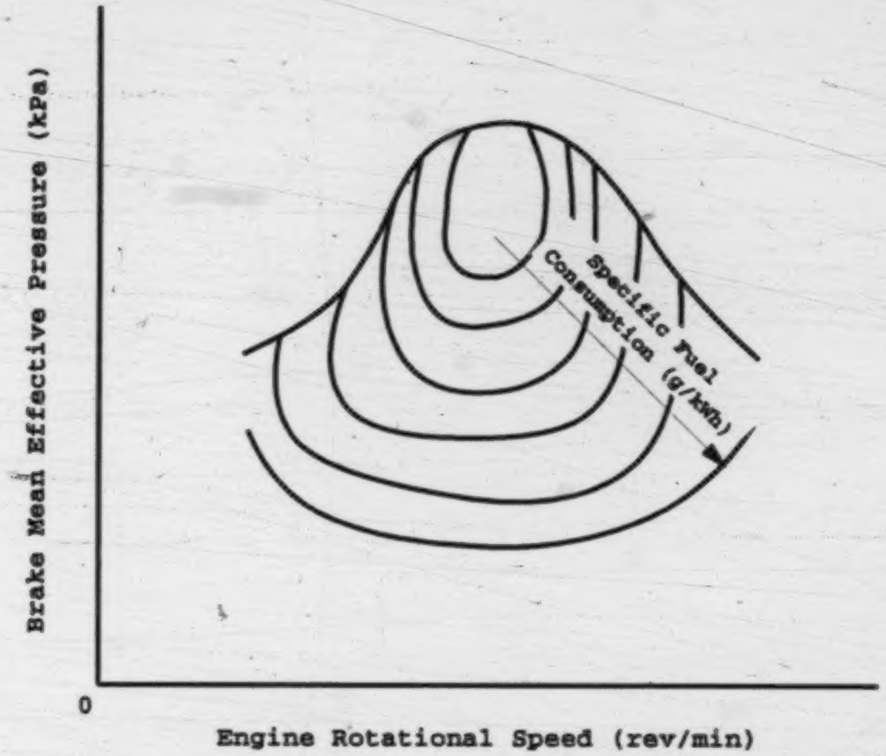

Brake Mean Effective Pressure (kPa)
Specific Fuel Consumption (g/kWh)
0
Engine Rotational Speed (rev/min)

Figure 5.2-9. Typical Diesel Engine Performance Diagram (based on [71])

as load levelling.

5.2.6.2. Load Data

Load demand data for 1993 - 1997 for several farms in the vicinity of Edmonton, Alberta was obtained from Atco Electric (formerly Alberta Power), two of which were selected for further examination. Figure 5.2-10 shows the histogram for one of the loads with the data for all 5 years combined together.

Similarly, load demand data was obtained for an undisclosed southern Alberta location from TransAlta Utilities, Calgary, Alberta, and for several agricultural facilities in British Columbia from B. C. Hydro, Vancouver, B. C.

These load data was in the form of accumulated energy use for each hour in terms of Watt-hours. For the purposes of this investigation, these values were converted to average hourly load demands by dividing the cumulative energy by the time interval (i. e., one hour).

For the remainder of this document, the Edmonton loads will be hereafter referred to as "Edmonton Load 1" and "Edmonton Load 2", the southern Alberta load as "Lethbridge", and the B. C. loads "Victoria" and "Delta".

5.3. Meteorological Data

5.3.1. Symbols

A = albedo
G_{on} = extraterrestrial irradiance (W/m^2)
G_{sc} = solar constant
$H(\beta,\gamma)$ = total tilted surface irradiance (W/m^2)
H_b = horizontal surface beam irradiance (W/m^2)
$H_d(\beta,\gamma)$ = tilted surface diffuse irradiance (W/m^2)
H_g = global horizontal surface irradiance (W/m^2)
$H_i(\beta_i,\gamma_i)$ = irradiance on i-th reflecting surface (W/m^2)
$H_r(\beta,\gamma)$ = tilted surface reflected irradiance (W/m^2)
i = number of reflecting surfaces
n = number of day of year (January 1 = 1, February 1 = 32...)
T_{r_b} = beam radiation atmospheric transmittance
β = surface tilt angle (degrees)
β_i = surface tilt angle of i-th reflecting surface (degrees)
δ = declination (degrees)
ϕ = latitude (degrees)
γ = surface azimuth angle (degrees) (due south 0°)
γ_i = surface azimuth angle of i-th reflecting surface

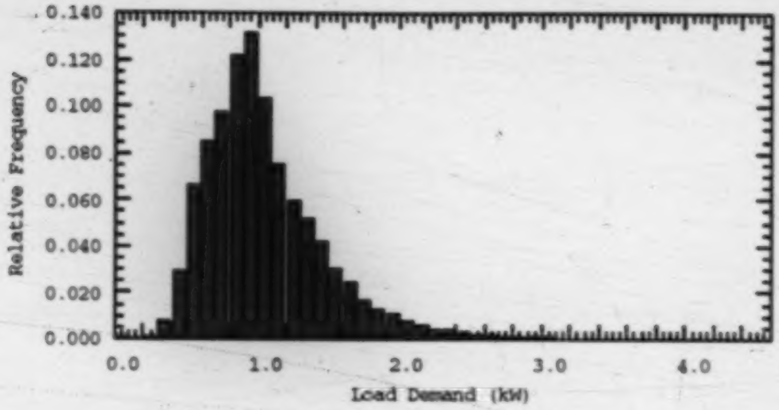


Figure 5.2-10. Load Demand for Edmonton Load 1 (5-Year Total Data Set)

(degrees) (due south 0°)

θ = incidence angle (degrees)

θ_i = incidence angle of reflected irradiance from *i*-th reflecting surface with respect to tilted surface (radians)

θ_z = solar zenith angle (radians)

ω = hour angle with respect to local standard noon (degrees) (mornings negative)

ω_i = solid angle of *i*-th reflecting surface with respect to tilted surface (steradians)

5.3.2. General

Meteorological data for several locations in Alberta and British Columbia were obtained from Environment Canada. These data included hourly values for:

- dry bulb temperature,
- wind speed,
- global solar radiation, and
- diffuse radiation (sometimes called sky radiation).

These data also include flags for the presence of snow cover. Details concerning the final data format used for this investigation are given in Appendix A.

5.3.3. Hourly Wind Speed

Details concerning the hourly wind speed are given in Appendix A. It should be noted that, for this investigation, the WTG height is assumed to be at the same elevation as that at which the wind speeds were measured.

5.3.4. Hourly Dry Bulb Temperature

Details concerning the hourly dry bulb temperatures are given in Appendix A.

5.3.5. Hourly Radiation

5.3.5.1. Declination

The declination is defined as the angle of the sun at local solar noon with respect to the equatorial plane. It was determined from [75]:

$$\delta = 23.45^\circ \sin\left[360^\circ\left(\frac{284 + n}{365}\right)\right]. \qquad (5.3.4\text{-}1)$$

For leap years, the value of 365 was replaced by 366.

5.3.5.2. Incidence Angle

The incidence angle is the angle between beam radiation incident on a surface and the normal to the surface and is determined from [75]:

$$\left.\begin{aligned}\cos\theta &= \sin\delta\sin\phi\cos\beta - \sin\delta\cos\phi\sin\beta\cos\gamma \\ &\quad + \cos\delta\cos\phi\cos\beta\cos\omega \\ &\quad + \cos\delta\sin\phi\sin\beta\cos\gamma\cos\omega \\ &\quad + \cos\delta\sin\beta\cos\gamma\sin\omega\end{aligned}\right\} \qquad (5.3.4\text{-}2)$$

Further details are given in Figure 5.3-1. The incidence angle for a horizontal surface was equal to the solar zenith angle. This angle was determined using (5.3.4-2), but setting the surface tilt angle to zero [76].

The hour angle was determined with respect to local solar noon at 15° per hour [75].

Latitudes for the various stations for which data were obtained are given in Table 5.3-1 [77], [78]. To simplify the calculations, the surface tilt angle was set to be equal to the local latitude throughout the year [79].

For simplicity, the surface was assumed to be facing due south, giving an azimuth angle of 0° [75].

5.3.5.3. Tilted Surface Irradiance

The values for both the hourly global solar radiation, and hourly sky radiation were for radiation incident on horizontal surfaces. (Sky radiation is also referred to as diffuse radiation [80].) The values for tilted surface irradiance were determined from them.

Global radiation is the sum of the beam radiation and sky radiation [80]. The value for hourly beam radiation was determined by subtracting the hourly sky radiation from the hourly global radiation.

Several expressions for determining irradiance on a tilted surface are available (see references such as [81]). One of the models considered was the expression given in [82]:

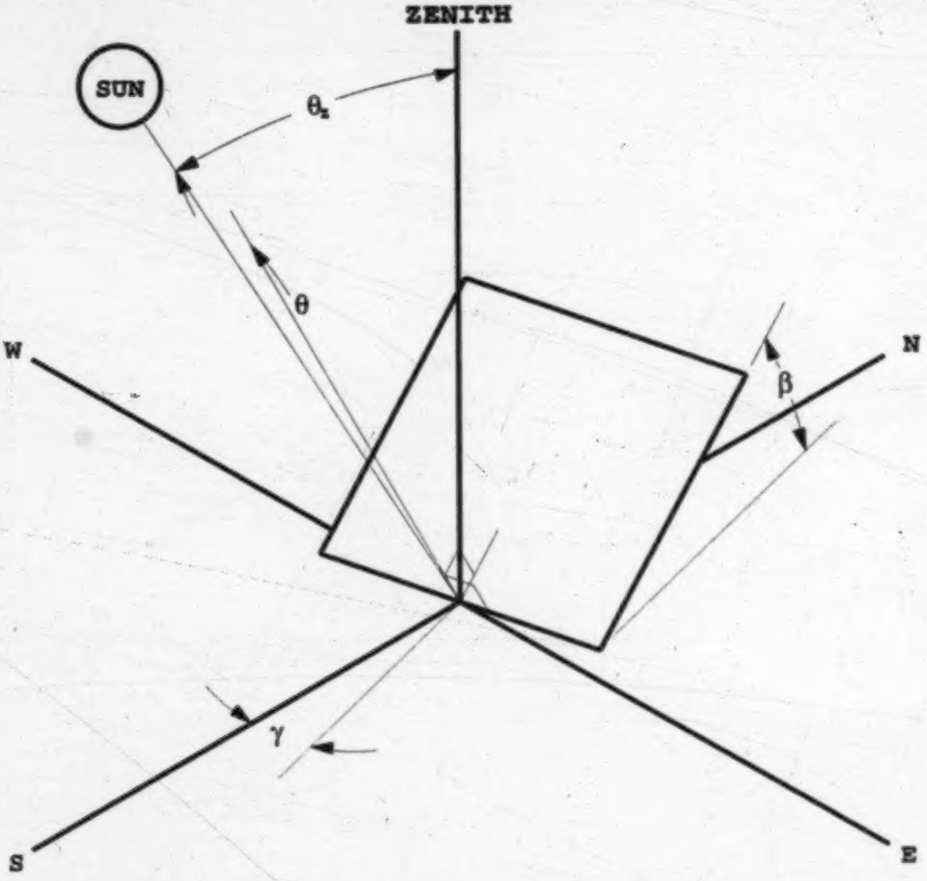

ZENITH
SUN
θ_z
θ
W
N
β
γ
S
E

Figure 5.3-1. Solar Zenith, Azimuth, and Surface Tilt Angles (based on [75])

Table 5.3-1. Meteorological Station Latitudes

Location	Latitude (°)
Edmonton/Stony Plain	53.55
Lethbridge	49.63
Victoria	48.65
Vancouver/Delta	49.18

References: [77], [78]

$$H(\beta, \gamma) = H_b \frac{\cos\theta}{\cos\theta_z} + H_d(\beta, \gamma) + H_r(\beta, \gamma), \quad (5.3.4\text{-}3)$$

which was selected due to:

- its ease of application,
- use of hourly meteorological data, and
- accounting for reflected radiation.

The beam irradiance on a tilted surface is given by [82], [83]:

$$H_b \frac{\cos\theta}{\cos\theta_z} \quad \ldots\ldots\ldots\ldots\ldots\ldots \quad (5.3.4\text{-}4)$$

This expression is set to zero to avoid unreasonably large values from occurring when both θ and θ_z are large since the radiation is either zero or negligible for larger angles [83]. The limit for θ_z was set at 85° in accordance with [82]. For simplicity, the limit for θ was set to the same value, with $\cos\theta$ being very small at large angles.

The diffuse tilted surface radiation is determined from [82]:

$$\left.\begin{aligned} H_d(\beta, \gamma) = H_d \Bigg[& T_{r_b}\left(\frac{\cos\theta}{\cos\theta_z}\right) + Z\cos\beta \\ & + \left(1 - T_{r_b} - Z\right)\cos^2\left(\frac{\beta}{2}\right) \\ & - \sum_i \left(\frac{1 - T_{r_b} - Z}{\pi}\right)\omega_i \cos\theta_i \Bigg] \end{aligned}\right\} \quad \ldots\ldots\ldots \quad (5.3.4\text{-}5)$$

$$\left.\begin{aligned} Z &= 0.3 - 2T_{r_b} \\ &\geq 0 \end{aligned}\right\} \quad \ldots\ldots\ldots\ldots\ldots\ldots \quad (5.3.4\text{-}6)$$

The solid and incidence angles are as given in [84]. These angles are used in determining the portion of the radiation which leaves a given reflecting surface and is intercepted by the tilted surface.

The beam radiation atmospheric transmittance was determined from [85]:

$$T_{r_b} = \frac{H_b}{G_{on}}, \quad (5.3.4\text{-}7)$$

with [86]:

$$G_{on} = G_{sc}\left\{1 + 0.033\cos\left[360^{\circ}\left(\frac{n}{365}\right)\right]\right\} \quad (5.3.4\text{-}8)$$

For this investigation, G_{SC} was taken as 1353 W/m^2, based on the value given in [86]. For leap years, the value of 365 was replaced by 366.

The reflected tilted surface irradiance was given from [87]:

$$H_r(\beta, \gamma) = \left[1 - \cos^2\left(\frac{\beta}{2}\right)\right] A H_g + A\sum_i \left[\frac{H(\beta_i, \gamma_i)}{\pi}\right]\omega_i \cos\theta_i , \quad (5.3.4\text{-}9)$$

For this investigation, the radiation is assumed to be measured in a large open area so that the summation terms in and (5.3.4-5) and (5.3.4-9) go to zero. This arises when surfaces such as building walls are not present or close by to contribute to the reflected radiation.

The values for the albedo at all locations were based on the values of the flags in each data string (as outlined in Appendix B) and are given in Table 5.3-2 [87]. It should be noted that due to the format of the original Lethbridge, Victoria, and Vancouver data (described in [78]), only the V and W flags were used for those locations.

For simplicity, albedo values for data points for which either snow cover was unknown or data available were set to zero. (For example, less than 6% of the values for Edmonton, including hours with no daylight, were affected.) The result is that the irradiance values calculated for those times may be lower by a few percent than if the average albedos were used. The values for the albedo were estimated from values given in [88].

5.4. Optimization Methods

5.4.1. General

5.4.1.1. Symbols

$f(\mathbf{x})$ = objective function
$g(\mathbf{x})$ = inequality constraints for optimization
$h(\mathbf{x})$ = equality constraints for optimization
$\mathbf{x}$ = optimization variables

Table 5.3-2. Albedo Values

Month	Flag	Albedo
January	V, Y	0.3
	W, Z	0.7
February	V, Y	0.3
	W, Z	0.7
March	V, Y	0.3
	W, Z	0.7
April	V, Y	0.2
	W, Z	0.45
May	V, Y	0.15
	W, Z	0.45
June	V, Y	0.15
	W, Z	0.45
July	V, Y	0.15
	W, Z	0.45
August	V, Y	0.15
	W, Z	0.45
September	V, Y	0.15
	W, Z	0.45
October	V, Y	0.2
	W, Z	0.45
November	V, Y	0.3
	W, Z	0.7
December	V, Y	0.3
	W, Z	0.7

Values based on [87], [88]

Note: All flags used for Edmonton data only. V and W flags used for remaining locations.

5.4.1.3. Problem Form

Each problem in optimization consists of [89]:

- one or more functions to be optimized (objective function), and
- constraints (equalities and inequalities).

This can be expressed as:

$$\left.\begin{array}{ll} \text{Minimize:} & f(\mathbf{x}) \\ & \\ \text{Subject to:} & \mathbf{h}(\mathbf{x}) = \mathbf{0} \\ & \mathbf{g}(\mathbf{x}) \geq \mathbf{0} \end{array}\right\} \dots\dots\dots\dots\dots \quad (5.4.1\text{-}1)$$

A feasible solution consists of a set of variables which satisfy the constraints, with an optimal solution being those variables which not only satisfy the constraints but also yield an optimum value for the objective function.

Many optimization methods are available, though none can be applied effectively and efficiently to all problems. The selection of a method depends on factors such as the characteristics of the objective function and constraints, as well as how the optimization problem is formulated.

Optimization methods are used in a variety of engineering applications including structural design and oil refinery operation [90].

For this investigation, a number of different methods were considered. The selection of the method that was used in this investigation was based on such aspects as:

- suitability for the problem being examined,
- types of constraints and limits to be satisfied, and
- ease of applicability.

5.4.2. Linear Programming

5.4.2.1. Symbols

$\mathbf{A}$ = constraint coefficients
$\mathbf{b}$ = constraint limits
$\mathbf{c}$ = objective function coefficients
$f(\mathbf{x})$ = objective function
$\mathbf{x}$ = optimization variables

5.4.2.2. General Method

In linear programming (LP), both the objective function and the constraints are linear expressions, with the problem often given in the form [91]:

$$\left.\begin{array}{ll} \text{Minimize:} & f(\mathbf{x}) = \mathbf{c}^T\mathbf{x} \\ \\ \text{Subject to:} & \mathbf{Ax} = \mathbf{b} \\ & \mathbf{x} \geq \mathbf{0} \\ & \mathbf{b} \geq \mathbf{0} \end{array}\right\} \quad \text{(5.4.2-1)}$$

One technique frequently used for solving LP problems is the Simplex method. This involves the introduction of slack and/or surplus variables which convert any inequality constraints into equalities. Slack variables are used for $\leq$ inequalities, while surplus variables are used for $\geq$ inequalities.

The general procedure is as follows:

- all inequalities are converted so that the right-hand sides of the constraints in (5.4.2-1) are positive,
- introduce slack and/or surplus variables to convert the inequality constraints into equality constraints,
- determine a basic solution (i. e., a solution corresponding to one corner of the region of feasibility [91]),
- select a new basic solution to improve the value of objective function,
- transformation of the equality constraint equations, and
- improvement of objective function by iteration until no further changes possible.

A number of computer programs are available for solving such problems [91].

5.4.2.3. Mixed-integer Linear Programming

A typical mixed-integer linear programming (MILP) problem is similar to (5.4.2-1) with the exception that at least one of the optimization variables must have an integer value, with the remainder continuous [92].

A number of methods for solving MILP problems are available.

Implicit enumeration is a search through different possible combinations of the integer variables in such a way so as to eliminate certain sets of solutions from any further consideration due to their unsuitability. This is because a complete enumeration in which all combinations are evaluated can become prohibitive [93].

In the branch and bound method, all possible feasible solutions are divided into subsets with the search for the optimum conducted among those remaining which are the most promising candidates. The general procedure is as follows [92]:

- obtain the continuous solution to the problem,
- check if the continuous solution satisfies the integer conditions--halt if the conditions are satisfied,
- select one integer variable with a non-integer value from the continuous solution as a branching node,
- add two nodes branching from the first node, given by the additional constraints:
    - one node variable greater than or equal to the smallest integer greater than the branching node value, and
    - the other node variable less than or equal to the largest integer less than the branching node value,
- solve the continuous problem with one of the additional constraints,
- branch at a new variable using the same partitioning criteria as before,
- continue branching on integer variables until either:
    - a solution satisfying the integer constraints is obtained,
    - the objective function of the sub-problem being evaluated is worse than any previously-obtained solution satisfying the integer constraints, or
    - no feasible solution obtained, and
- return to a previous node on the same branch and solve for the other constraint.

5.4.3. Non-linear Programming

5.4.3.1. Symbols

$\mathbf{A}$ = constraint coefficients
$\mathbf{b}$ = constraint limits
$\mathbf{c}$ = objective function coefficients
$f(\mathbf{x})$ = objective function
$f(x_A)$ = objective function value at x_A
$f(x_B)$ = objective function value at x_B
$f[\theta x_A + (1 - \theta)x_B]$ = objective function convexity check value
$g(\mathbf{x})$ = inequality constraints for optimization
$g_j(\mathbf{x})$ = j-th non-linear programming inequality constraint
$h(\mathbf{x})$ = equality constraints for optimization
$h_j(\mathbf{x})$ = j-th non-linear programming equality constraint
j = non-linear programming constraint index
$L(\mathbf{x}, \omega)$ = Lagrangian function
m = number of non-linear programming constraints
p = total number of non-linear programming constraints
$P[f(\mathbf{x}), g(\mathbf{x}), h(\mathbf{x})]$ = penalty function
$\mathbf{Q}$ = quadratic programming coefficients
$\mathbf{x}$ = optimization variables
x_A = convexity/concavity check variable
x_B = convexity/concavity check variable
θ = convexity/concavity scalar
σ_j = Lagrangian slack variable
ω = Lagrangian multiplier
ω_j = j-th Lagrangian multiplier

5.4.3.2. General

In non-linear programming (NLP), an objective function is subject to constraints which can be either linear or non-linear expressions, with the problem often given as [94]:

$$\left.\begin{array}{ll} \text{Minimize:} & f(\mathbf{x}) \\ \\ \text{Subject to:} & h_j(\mathbf{x}) = 0 \quad j = 1, 2, \ldots, m \\ & g_j(\mathbf{x}) \geq 0 \quad j = m + 1, \ldots, p \end{array}\right\} \ldots\ldots\ldots\ldots\ldots \text{(5.4.3-1)}$$

Often, the inequalities are changed into equalities, with the problem then becoming one subject only to equality constraints.

Several methods for solving non-linear programming problems exist with the solution often based on one of the following:

- Lagrange multipliers,
- iterative quadratic programming,
- iterative linearization, or
- penalty functions.

This section is a brief description of these methods, with further details available in references such as [94].

It is emphasized that no one method will be suitable for each optimization problem. For some types of problems in NLP, though, software is commercially available and can be used to solve them. Most of the codes listed in [94] cannot be used on personal computers and are only available at considerable cost, limiting their applicability to this investigation.

5.4.3.3. Lagrange Multiplier Method

In the Lagrange multiplier method [94], the problem described by (5.4.3-1) is converted to one in which only equality constraints exist so that:

$$\left.\begin{array}{lrl} \text{Minimize:} & f(\mathbf{x}) & \\ \text{Subject to:} & h_j(\mathbf{x}) = 0 & j = 1, 2, \ldots, m \\ & g_j(\mathbf{x}) - \sigma_j^2 = 0 & j = m+1, \ldots, p \end{array}\right\} \quad \ldots\ldots\ldots\ldots (5.4.3\text{-}2)$$

The following Lagrangian function can be defined:

$$L(\mathbf{x}, \omega) = f(\mathbf{x}) + \sum_{j=1}^{m} \omega_j h_j(\mathbf{x}) + \sum_{j=m+1}^{p} \omega_j \left[g_j(\mathbf{x}) - \sigma_j^2 \right]. \quad \ldots\ldots\ldots (5.4.3\text{-}3)$$

The factors ω_j are the Lagrange multipliers and are independent of $\mathbf{x}$.

An optimal solution exists if:

- the objective function at the optimal solution is convex,
- the constraints are convex in the vicinity of the optimal solution,
- the partial derivatives of (5.4.3-3) with respect to the optimization variables, ω_j, and σ_j at the optimal solution are zero, and

- $\omega_j \leq 0$ (maximum) or $\omega_j \geq 0$ (minimum).

A function is convex throughout a region if, for any two values of the variable x inside that region (x_A and x_B), the following condition holds (using the notation in [95]):

$$f[\theta x_A + (1-\theta)x_B] \geq \theta f(x_A) - (1-\theta)f(x_B) \quad 0 \leq \theta \leq 1, \quad \ldots\ldots \quad (5.4.3\text{-}4)$$

with θ a scalar.

5.4.3.4. Quadratic Programming

A typical quadratic programming problem has the form [94]:

$$\left.\begin{array}{ll} \text{Minimize:} & f(\mathbf{x}) = \mathbf{c}^T\mathbf{x} + \frac{1}{2}\mathbf{x}^T\mathbf{Q}\mathbf{x} \\ & \\ \text{Subject to:} & \mathbf{A}\mathbf{x} \geq \mathbf{b} \\ & \mathbf{x} \geq \mathbf{0} \end{array}\right\} \ldots\ldots\ldots\ldots\ldots\ldots \quad (5.4.3\text{-}5)$$

A Lagrangian function is formulated, and the gradient with respect to $\mathbf{x}^T$ is calculated and set to zero. This eventually yields a set of linear equations in which are included a set of Lagrange multipliers and slack variables. The variables (including the Lagrange multipliers) which satisfy these equations comprise the optimal solution.

Software programs for solving this type of problem are available [94].

5.4.3.5. Generalized Reduced Gradient Method

A direct approach to solving a general NLP problem is as follows [94]:

- derive a model based on a nominal operating point,
- linearize the objective function and constraints about the nominal point,
- solve the linearized problem using LP,
- successively linearize the objective function and constraints until a solution of the nominal problem is obtained and the nominal optimum is determined to be non-feasible,
- select a new feasible nominal point and linearize the objective function and constraints as before, and

- linearize the functions in a piece-wise manner to approximate the constraints and objective function by a set of straight lines.

The generalized reduced gradient method [94] reduces the search dimensionality to the number of optimization variables minus the number of independent constraints. This occurs in the following steps:

- determine the components for the independent variable search,
- determine the components for the dependent variable search,
- improve the objective function value, and
- utilize Newton's method for determining roots to obtain a set of dependent variables satisfying the constraints.

5.4.3.6. Penalty Functions

A penalty function method changes the problem described by (5.4.3-1) into the form [94]:

$$\left.\begin{array}{ll}\text{Minimize:} & f(\mathbf{x}) \\ & \\ \text{Subject to:} & h(\mathbf{x}) = 0 \\ & g(\mathbf{x}) \ge 0\end{array}\right\} \rightarrow \text{Minimize: } F\left[f(\mathbf{x}), g(\mathbf{x}), h(\mathbf{x})\right] \ldots \quad (5.4.3\text{-}6)$$

The penalty function (sometimes known as an augmented function) is minimized in stages for a range of penalty parameter values. These parameters are revised for each consecutive unconstrained minimization, forcing $\mathbf{x}$ towards the optimum for (5.4.3-1).

The effect of this is to convert a problem with constraints into a set of functions with no constraints, having the same form as before but different values for the parameters.

5.4.3.6. Mixed-integer Non-linear Programming

Most methods of mixed-integer non-linear programming (MINLP) are based on at least one of the following approaches [96]:

- rounding continuous optimum,
- use of non-linear optimization methods,

- linear approximation,
- binary variables, or
- direct search.

The effectiveness of any MINLP method depends upon the optimization problem, with no particular technique being suitable for all situations.

The most frequent approach starts with handling the optimization variables as continuous. A feasible set of values close to the continuous optimum is selected, though this may not necessarily be the optimum for the discrete case. However, the result may be suitable for practical purposes.

5.4.4. Dynamic Programming

5.4.4.1. Symbols

d_n = n-th dynamic programming stage decision variable
$f_n(x_n)$ = n-th dynamic programming stage return
$f_{n-1}(x_{n-1})$ = $(n - 1)$-th dynamic programming stage return
n = dynamic programming stage number
R_n = n-th dynamic programming stage objective function
x_n = n-th dynamic programming stage input
x_{n-1} = n-th dynamic programming stage output

5.4.4.2. General

A number of engineering systems can be represented as multi-stage processes, with each stage in a given process having the following characteristics [97]:

- objective function value (return) at each stage,
- stage indicator,
- input variables,
- output variables, and
- decision variables.

A typical situation can be seen in Figure 5.4-1.

One example of a staged process would be a natural gas processing plant in which the objective function could be minimum amount of energy (and, ultimately, the cost) required to operate the facility.

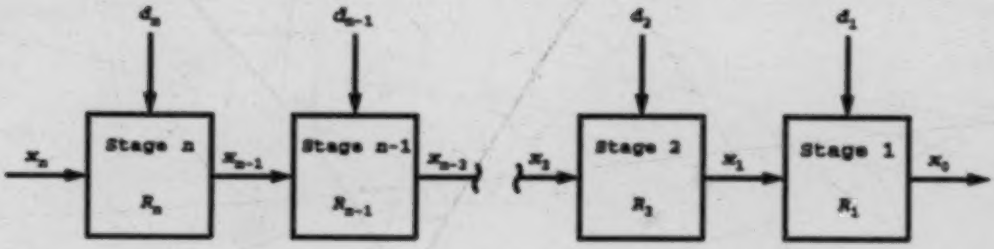

d_n
d_{n-1}
d_2
d_1
x_n
Stage n
R_n
x_{n-1}
Stage n-1
R_{n-1}
x_{n-2}
x_2
Stage 2
R_2
x_1
Stage 1
R_1
x_0

Figure 5.4-1. Typical Multi-stage Process (based on [97])

For instance, at the stage in which hydrogen sulphide is removed from the sour gas, the gas and the amine used to remove the H_2S might be considered as input variables for that process unit, depending on how it is modelled. The sweet gas and the amine containing the H_2S could be the output variables. Operating parameters such as flow rates, temperatures, and pressures could be used as the decision variables.

Dynamic programming is a method used to analyze multi-stage systems. The problem is separated into a set of sequential sub-problems which can then be solved in series. Detailed presentations of this method are in references such as [98] - [100].

5.4.4.3. Procedure

Bellman's optimality principle forms the basis of dynamic programming, which can be expressed as [97]:

$$f_n(x_n) = \max_{d_n}\left[R_n + f_{n-1}(x_{n-1})\right] \quad \text{(5.4.4-1)}$$

One of the advantages to this method is that it can applied to mixed-integer problems. However, only a small number of state variables can be handled and problems involving recycling or branching involve iterative solutions.

The optimization of several variables can be accomplished by the use of successive approximations [101], [102]. Some of the optimization variables are fixed, with the remainder being optimized. The process is then reversed with the newly-optimized variables being fixed and those previously held constant then being optimized. This process is repeated iteratively until convergence.

In order to facilitate the optimization process, a feasible region can be defined using multiple passes. A coarse grid in time and state is first laid out and an optimization performed, defining an initial trajectory. This trajectory forms the basis for a succeeding grid with the intervals in both state and time successively reduced with each new pass. When the time intervals are as small as required, only the state intervals are then reduced until convergence. Further details are available in references such as [63], [103], [104].

5.4.5. Luus-Jaakola Direct Search Method

5.4.5.1. Symbols

i = Luus-Jaakola direct search method optimization variable index

j = Luus-Jaakola direct search method index

$r_i^{(j)}$ = range for i-th Luus-Jaakola search method optimization variable during j-th iteration

$r_i^{(j-1)}$ = range for i-th Luus-Jaakola search method optimization variable during (j - 1)-th iteration

$x_i^{(j)}$ = i-th Luus-Jaakola search method optimization variable during j-th iteration

$x_i^{*(j-1)}$ = initial value for i-th Luus-Jaakola search method optimization variable during (j - 1)-th iteration

y_i = random number for i-th Luus-Jaakola search method optimization variable

ε = reduction factor for Luus-Jaakola search method optimization variable range

5.4.5.2. General Procedure

Direct methods based on random searches are another means by which systems can be optimized [105], [106]. The Luus-Jaakola (LJ) direct search method [107] - [109] is based on random numbers and the reduction of the search region. The general procedure is as follows:

1. initialize the values and ranges for the optimization variables, setting the iteration index to 1,

2. generate a set of random numbers y_i (say, between -0.5 and 0.5),

3. estimate the random values for the optimization variables with:

   $x_i^{(j)} = x_i^{*(j-1)} + y_i r_i^{(j-1)}$, and .... (5.4.5-1)

4. determine if the given set of random values satisfies the optimization constraints,

5. calculate the objective function for each valid set of random values,

6. determine the set of random values giving the best result for the objective function and save it as the new x_i^*,

7. increment the iteration index by 1,

8. stop if number of iterations reaches maximum,

9. reduce the range of the optimization variables by:

$$r_i^{(j)} = \varepsilon r_i^{(j-1)} \qquad 0 < \varepsilon < 1, \text{ and} \quad \ldots\ldots\ldots\ldots\ldots\ldots \quad (5.4.5\text{-}2)$$

10. return to Step 2 and continue.

A computer program using this method is presented in [108].

A recent revision of this method using multiple passes is described in [109] in which the range for the optimization variables is reset after each pass.

5.4.5.3. Mixed-Integer Programming

One method of mixed-integer programming based on the LJ direct search method is described in [110]:

1. obtain an approximate solution based on continuous values for the optimization variables,
2. truncate the continuous values for the integer variables in order to satisfy the constraints,
3. increment each integer variable by 1 to check if the constraints are satisfied, with only those variables which give the greatest contribution to optimizing the objective function being incremented,
4. continue with Step 3 until no integer variable can be incremented without violating the constraints,
5. increment one integer variable while decrementing the remainder and check for any constraint violations, calculating the objective function for each case and retaining the most optimum value (and the corresponding set of variables) after comparing with previous value, and
6. continue the procedure for the remaining variables and stop when no further improvement in the objective function is possible.

5.4.6. Stochastic Programming

5.4.6.1. Symbols

A = member of stochastic programming problem σ-field
F = stochastic programming problem σ-field
$g_i\left(x, \tilde{\xi}\right)$ = i-th stochastic programming problem constraint
$g_0\left(x, \tilde{\xi}\right)$ = stochastic programming problem objective function
i = stochastic programming constraint index

m = number of stochastic programming constraints
P = stochastic programming problem set function

S = stochastic programming sample space
x = stochastic programming problem optimization variables
$\tilde{\xi}$ = stochastic programming problem random vector

5.4.6.2. General

The methods examined so far have not accounted for any randomness in the problem described by (5.4.1-1).

In a number of cases, the assumption that the coefficients and the functions used in the formulation are deterministic is not reasonable [111]. It is not always possible to remove uncertainty about these parameters through the use of estimated values, such as the means of the associated probability density functions. Load demands, for example, may possibly be best represented by probability distributions and modelled as parameters possessing some degree of uncertainty.

An optimization problem becomes one in stochastic programming through the introduction of randomness, typically involving random variable functions [111], [112]. Given a suitable probability space, the general non-linear programming problem is given as:

$$\left.\begin{array}{l} \text{"Minimize"}:\ g_0\left(x, \tilde{\xi}\right) \\ \\ \text{Subject to:}\ g_i\left(x, \tilde{\xi}\right) \le 0 \quad (i = 1, \dots, m) \end{array}\right\} \dots\dots\dots\dots \quad (5.4.6.\text{-}1)$$

The probability space is comprised of the sample space (i. e., the entire set of possible trial outcomes) S, the σ-field (i. e., a collection of subsets of S) F, and the set function P and is denoted as the triple [112] - [115]:

$$(S, F, P). \dots\dots\dots\dots\dots\dots\dots\dots\dots\dots \quad (5.4.6.\text{-}2)$$

The set function P value, for any member A of F, is the probability of A.

The problem as such is not properly defined due to the meaning of the minimization as well as the constraints being unclear [111], [112]. Several formulations are possible, depending upon:

- timing of decisions with respect to how the random variables are realized,

- degree to which constraints are met, and
- choice of objective function.

Three types of problems which may be applicable to the investigation are:

- recourse problems [111], [112], [116], [117],
- stochastic dynamic programming and scenario aggregation [118], and
- chance-constrained problems [111], [112], [119].

5.4.6.3. Recourse Problems

The basis for recourse problems is that any discrepancies in the constraints will result in a penalty, so that the objective function could become the minimization of the total of the objective function and the expected values of these penalties [120].

This requires that the recourse be determined in a separate stage, resulting in what is known as a two-stage problem. The first-stage costs are, for example, those due to production, such as fuel for a power station. The second-stage costs are concerned with the recourse. Recourse costs are those associated with any violation of the constraints and are determined after observing the random variables involved. For example, during periods of excessively high load demands which were not foreseen, a power company may have to purchase electricity from another source in order to fulfil its contractual requirements or to prevent brownouts.

This can be extended to a multi-stage recourse program [116].

5.4.6.4. Stochastic Decision Trees

Stochastic decision trees are one means by which dynamic systems can be analyzed and can be understood by first considering sequential decision trees [117].

Sequential decision trees consist of a set of nodes and arcs, starting with some initial conditions. At each stage in the process, a set of possible states exist, represented by decision nodes. At each state, a number of decisions are possible, each of which is represented by an arc. This branching continues until the end of the process.

Starting from the final possible states, the optimum path is found by determining the best decision at each decision node (a process known as folding back). This process continues until the root node.

Stochastic decisions trees are similar except that uncertainty is introduced through the use of chance nodes. A decision tree is constructed as before, but instead of directly connecting one decision node to a subsequent one by a single arc, an arc is connected from the decision node to a chance node. At the chance node, some action occurs, such as, say, information on interest rates becoming available, and then arcs branch out from that chance node to the subsequent decision nodes, based upon the outcome of the event.

The optimum path is determined as before by folding back up the decision tree from one stage to the next.

5.4.6.5. Stochastic Dynamic Programming

Stochastic dynamic programming has some similarities to dynamic programming [118]. For every state in every stage, a decision is made, but it will not be possible to determine the entire period beforehand. Each decision, except for that during the first period, will be dependent upon what happens during the interim time.

This process involves a recursive procedure in which the expected value of a return function is minimized, and is of a form similar to (5.4.4-1).

5.4.6.6. Scenario Aggregation

Stochastic decision trees and stochastic dynamic programming are both applicable to cases in which a finite number of possible states at each stage exist [118]. There are, however, situations in which there are continuous distributions of the random variables and a continuous number of decisions, with the provision that the expectation with respect to the random variables can be determined.

Scenario aggregation can be used for handling such problems. An event tree is first constructed. At each stage, a branch exists for each possible value of the random variables, requiring both limitations on these values as well as finite discrete distributions. Continuous optimization variables are preferred.

Given a number of time periods and a vector describing what occurs during each one, the set of these vectors is a scenario (i. e., one possible representation of the future). A set of equations is often solved, the solution of which for each scenario allows the determination of a set of implementable decisions for each event tree node.

For multi-stage scenario problems, these decisions can be moved into the objective function in the form of penalty functions, assuming discrete distributions. The solution can be determined by, for example, an augmented Lagrangian method, though the problem becomes more difficult to solve due to the increased magnitude of the problem.

5.4.6.7. Chance Constraints

Chance-constrained problems have a form in which the probabilities that individual constraints are met become constraints themselves [112], [119].

In the case of a linear programming problem in which there are random parameters, it is important to know if the constraints are independent as well as the form of the distributions for the random variables [121]. Traditionally, these problems were modelled using normal distributions for the random variables.

For cases in which the distributions are discrete and the reliability sufficiently large, the problem becomes convex [119].

5.4.7. Genetic Algorithms

A number of optimization problems cannot be readily handled by analytical techniques [122]. Such problems could possibly be solved using approaches based on biological concepts. Examples are genetic algorithms and neural networks.

A genetic algorithm is not an optimization method like those previously described, though it can be used for that purpose. Instead, it is a simulation of an evolutionary system, requiring that the problem be posed in a manner different than would be the case for the previous optimization methods.

Of interest is the type of behaviour that arises from the rules that are imposed and how this behaviour is affected by changes in the algorithm.

A generic form of a genetic algorithm is given in Figure 5.4-2. Genetic algorithms have been applied to the optimization of renewable energy systems [26].

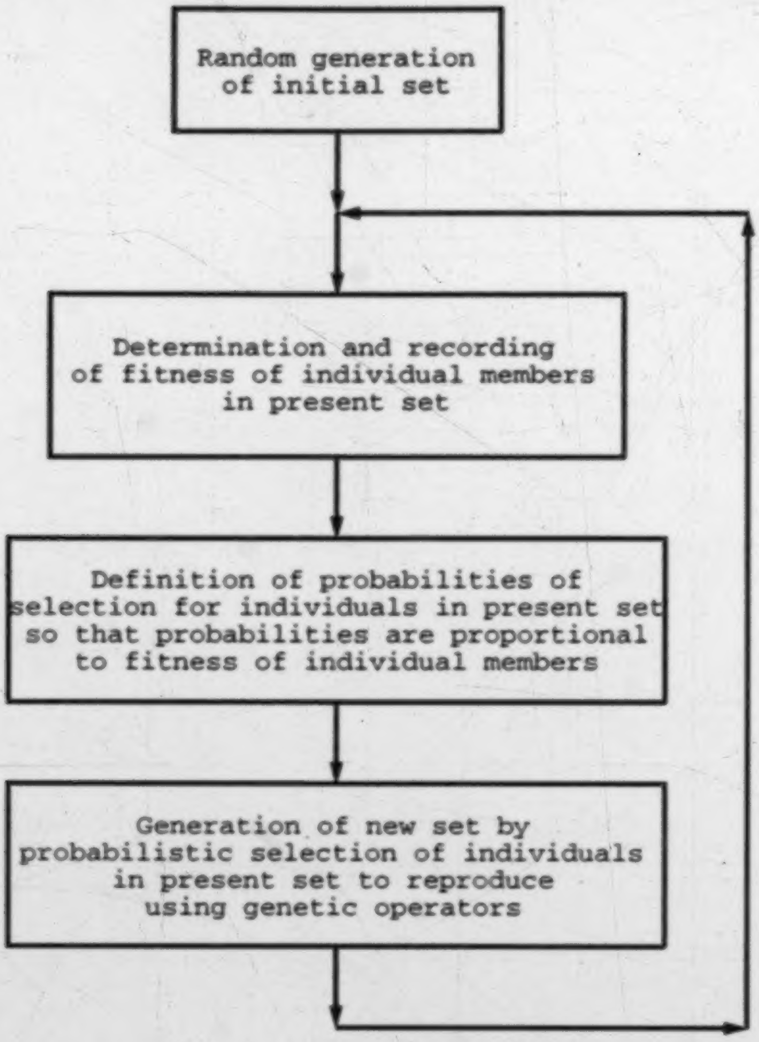

Random generation of initial set
Determination and recording of fitness of individual members in present set
Definition of probabilities of selection for individuals in present set so that probabilities are proportional to fitness of individual members
Generation of new set by probabilistic selection of individuals in present set to reproduce using genetic operators

Figure 5.4-2. Generic Genetic Algorithm (based on [122])

5.5. Data Processing and Modelling

5.5.1. General

Hourly values for meteorological data and load demand data for several locations in Alberta and British Columbia were obtained. These data were converted from their original forms into ones suitable for further analysis. It is required that the optimization method selected in this investigation be capable of utilizing these data.

5.5.2. Data Sets

The meteorological and load demand data were divided into several sets for use in this investigation.

- entire data set (summer and winter together),
- entire data set (summer only),
- entire data set (winter only),
- values for each hour of the day (summer and winter together),
- values for each hour of the day (summer only), and
- values for each hour of the day (winter only).

Summer was taken from the spring to the autumn equinox with winter being the remainder. A 365 day year was assumed.

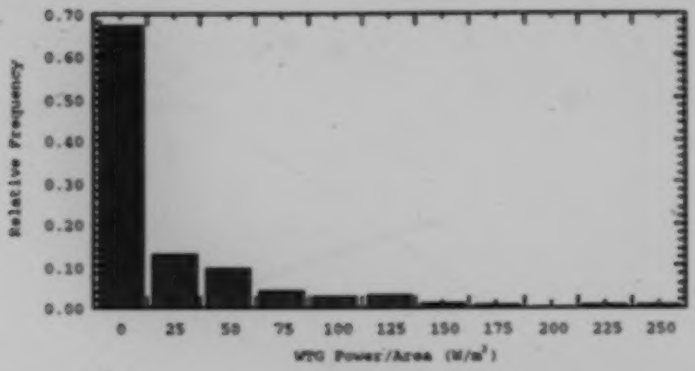
5.5.3. Renewable Energy Source Output Power Data

The meteorological data were read sequentially and the WTG output power/unit area and the PV module output power for each hour were calculated using the expressions outlined in 5.2.2. and 5.2.3. These data were divided into the same data sets as given in 5.5.2.

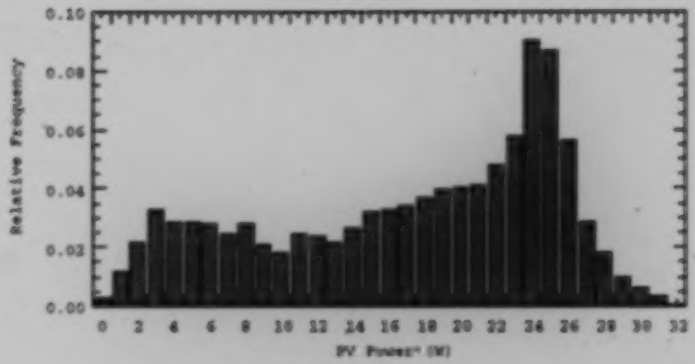
5.5.4. Histograms

The data sets in 5.5.1. and 5.5.2. were used to obtain histograms, examples of which are shown in Figure 5.5-1. For this figure, the WTG had a rated speed of 40 km/hr, a cut-in speed of 12 km/hr, and a cut-out speed of 120 km/hr.

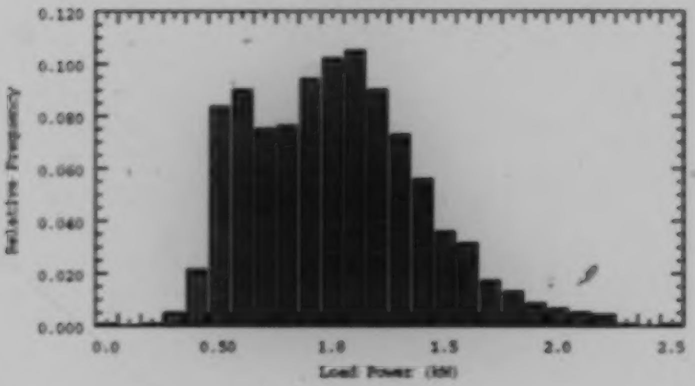
From these, statistical parameters such as means can be determined. It should be noted that for the PV module histograms, a 12-V constant load was assumed (see 5.2.2, and Figure 5.2-3).



0900 Hours



1400 Hours



1900 Hours

Fig. 5.5-1. Typical Wind Turbine Generator Output Power/Area, Photovoltaic Module Output Power, and Load Demand Histograms for Edmonton Load 1 (Summer Data Set)

5.5.5. Hourly Average Variations

The information conveyed in the histograms can be supplemented by considering the variation of the data throughout the day. Figure 5.5-2 shows the variation of the average values for the WTG output power/unit area, PV module output power, and the load demand throughout the day for both the total data set and summer and winter.

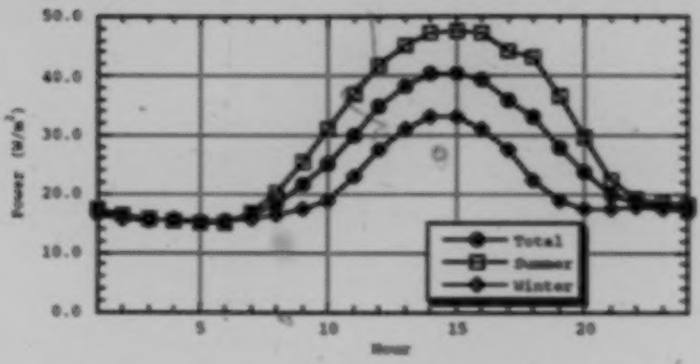
5.6. Optimization Constraints and Limits

5.6.1. Symbols

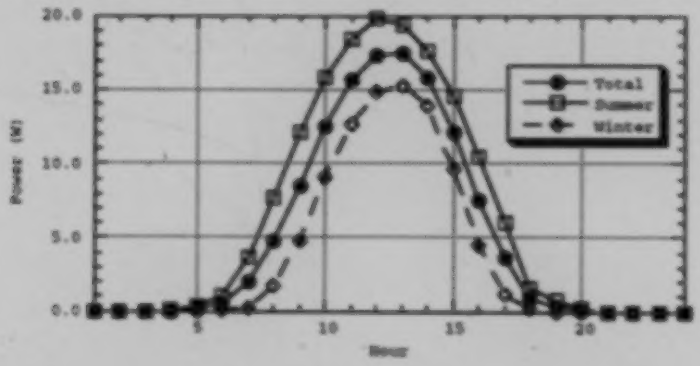
A_W = wind turbine generator rotor area (m^2)
$A_{W_{MAX}}$ = maximum wind turbine generator rotor area (m^2)
$A_{W_{MIN}}$ = minimum wind turbine generator rotor area (m^2)
C_P = wind turbine generator coefficient of performance
E_0 = internal battery cell voltage (V)
I_{B_t} = battery current at time t (V)
n = number of time intervals since start of process
N_B = number of batteries
$N_{B_{MAX}}$ = maximum number of batteries
$N_{B_{MIN}}$ = minimum number of batteries
N_S = number of photovoltaic modules
$N_{S_{MAX}}$ = maximum number of photovoltaic modules
$N_{S_{MIN}}$ = minimum number of photovoltaic modules
$P_{G_{MAX}}$ = maximum auxiliary generator capacity (W)
$P_{G_{MIN}}$ = minimum auxiliary generator capacity (W)
P_G = required auxiliary generator capacity (W)
P_{L_t} = load demand at time t (W)
P_{S_t} = photovoltaic module output power at time t (W)
P_{W_t} = available wind turbine generator output power per unit area at time t (W/m^2)
Q_F = final battery charge (A-hr)
Q_{MAX} = maximum battery capacity (A-hr)
Q_{MIN} = minimum battery capacity (A-hr)
Q_t = battery capacity at time t (A-hr)
Q_{t-1} = battery capacity at time t - 1 (A-hr)
Q_{U_t} = maximum allowed battery capacity at time t (A-hr)
Q_0 = initial battery charge (A-hr)
V_{B_t} = battery cell voltage at time t (V)
Δt = time interval (hr)
η_I = inverter efficiency
τ_C = allowed battery charge time (hr)
τ_D = allowed battery discharge time (hr)

5.6.2. General

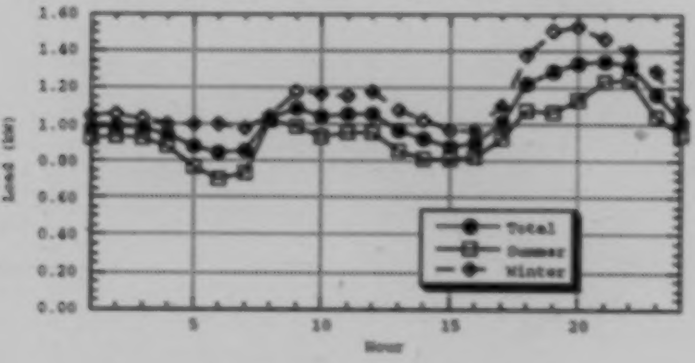
The optimization method that is selected for this investigation must handle the constraints and limits imposed on the system. These constraints are due to such things as physical requirements



Average Hourly WTG Output Power/Unit Area



Average Hourly PV Module Output Power



Average Hourly Load Demand

Fig. 5.5-2. Hourly Variations in Average Wind Turbine Generator Output Power/Area, Photovoltaic Module Output Power, and Load Demand for Edmonton Load 1

of the system and operational parameters.

Because the system may require batteries, the optimization must determine both the optimum trajectory through a battery during the duty cycle plus the overall system configuration.

Since, in 5.5., the data were divided into hourly sets, the system examined is assumed to operate on a 24-hour cycle.

5.6.3. Battery Constraints

5.6.3.1. Duty Cycle

At the beginning of the duty cycle, the batteries will have an initial state of charge (SOC). For this investigation, it is assumed that the batteries will return to that state of charge at the end of the 24 hours. Farming operations, such as those for livestock, often run on a daily cycle, with the loads repeating each day.

5.6.3.2. Charge

For a given hour, the battery charge is taken as:

$$Q_t = Q_{t-1} + I_{B_t}\Delta t, \quad \ldots\ldots (5.6.3\text{-}1)$$

and is bounded during operation by the following envelope [63], [103], [104]:

$$\left.\begin{aligned} Q_t &= Q_0 + \left(\frac{Q_{MAX}}{\tau_C}\right) n\Delta t \\ &= Q_0 - \left(\frac{Q_{MAX}}{\tau_D}\right) n\Delta t \\ &= Q_F - \left(\frac{Q_{MAX}}{\tau_C}\right)(24 - n)\Delta t \\ &= Q_F + \left(\frac{Q_{MAX}}{\tau_D}\right)(24 - n)\Delta t \end{aligned}\right\} \quad \ldots\ldots (5.6.3\text{-}2)$$

$$\left(Q_{MIN} \le Q_t \le Q_{MAX}\right).$$

These limits define the charge range for the battery for each time period and prevent it from excessively charging or discharging throughout the process.

The current in (5.6.3-1) is assumed to be constant throughout a given hour.

Prior to starting the optimization, the following must be specified:

- Q_0,
- Q_F,
- Q_{MAX}, and
- Q_{MIN}.

5.6.3.3. Current

For each hour, the maximum battery charge rate is assumed to be $c/10$ and the maximum discharge rate $c/20$ [123]:

$$-\frac{Q_{MAX}}{\tau_C} \leq I_{B_t} \leq \frac{Q_{MAX}}{\tau_D} \quad \text{(5.6.3-3)}$$

5.6.3.4. Voltage

During a given hour, the nominal battery cell voltage, E_0, (as given in (5.2.4-6)) is taken as 2.0 V, with the allowable range during operation given as [63]:

$$0.85E_0 \leq V_{B_t} \leq 1.2E_0 \quad \text{(5.6.3-4)}$$

5.6.4. Overall System Constraints

5.6.4.1. Daytime Operation

One requirement for the hybrid energy system is that the renewable sources are utilized as much as possible. This can be accomplished by constraining the system so that the load demand is either met or exceeded when sufficient renewable energy is available, or:

$$A_W C_P P_{W_t} + \eta_I N_S P_{S_t} \geq P_{L_t} \quad \text{(5.6.4-1)}$$

The times during which this constraint is applicable will depend upon the location in question and can best be determined after examining the applicable meteorological data and the corresponding renewable energy source output powers.

Any excess power during that time will be used for battery charging, if required.

5.6.4.2. Battery Charging

During the hours in which (5.6.4-1) will be in effect, the system will be constrained so that the battery will be charged from either the PV modules only or the WTG only, depending upon the availability of sufficient power from each source.

Using a single renewable energy source for charging the batteries accounts for extreme cases in which energy from either one or the other source is available.

Early in the investigation, it was found that during simultaneous charging by the PV modules and the WTG and/or auxiliary generator after the load demand was met, the power provided by at least one of the sources to the batteries would have to be known beforehand.

Referring to Table 5.2-1, all but two of the switch combinations were considered. The exceptions are the case for which only S_G is open and the one when all switches are closed.

5.6.4.3. Power Difference

The components for the renewable energy system should be selected by the optimization method such that, for a given time, the following conditions are met:

$$\text{Minimize: } \left|A_W C_P P_{W_t} + \eta_I N_S P_{S_t} + N_B P_{B_t} - P_{L_t}\right|, \text{ and} \quad \text{..........} \quad (5.6.4\text{-}2)$$

$$P_{L_t} - \left(A_W C_P P_{W_t} + \eta_I N_S P_{S_t} + N_B P_{B_t}\right) \leq P_{G_{max}} \quad \text{.................} \quad (5.6.4\text{-}3)$$

Equation (5.6.4-2) minimizes the total power from the PV modules, WTG's, and batteries either less than or in excess of the load demand during a given time interval. On the other hand, (5.6.4-2) limits the difference between the load demand and the total power from the renewable energy sources to less than or equal to the maximum allowable auxiliary generator capacity.

5.6.4.5. Component Capacities/Sizes

The capacities of the energy sources are bounded by:

$$\left.\begin{array}{lllll} A_{W_{min}} & \leq & A_W & \leq & A_{W_{max}} \\ N_{S_{min}} & \leq & N_S & \leq & N_{S_{max}} \\ N_{B_{min}} & \leq & N_B & \leq & N_{B_{max}} \\ P_{G_{min}} & \leq & P_G^{*} & \leq & P_{G_{max}} \end{array}\right\} \quad \text{..............................} \quad (5.6.4.4)$$

The values for the upper and lower limits will be dependent upon the meteorological conditions at the location in question as well as the applicable load profile.

5.7. Selection of Optimization Method

5.7.1. Symbols

f_C = battery charge flag
f_D = battery discharge flag
ΔQ = change in battery charge (A-hr)

5.7.2. Requirements for Selected Method

The optimization method which is selected must account for the operation of the battery and the constraints outlined in 5.6. From expressions such as (5.2.4-6) and (5.6.4-2), it can be seen that the system being investigated is non-linear.

From (5.6.3-1), the battery state of charge for a given hour is dependent upon its value for the previous hour. The selected optimization method must account for the change in that state of charge with respect to time and determine whether the battery is charging or discharging. One way this can be accomplished is by means of a binary variable which would take the value of 0 or 1 [93], possibly through functions such as:

$$\left.\begin{aligned} f_C &= \frac{1}{2}\left(1 - \frac{|\Delta Q|}{\Delta Q}\right) \\ &= 0, 1 \\[2ex] f_D &= \frac{1}{2}\left(1 + \frac{|\Delta Q|}{\Delta Q}\right) \\ &= 0, 1 \\[2ex] f_C + f_D &= 1 \end{aligned}\right\} \quad \ldots\ldots\ldots\ldots\ldots\ldots \quad (5.7.2\text{-}1)$$

Another requirement for the selected optimization method is ease of implementation in a computer program. Those methods not involving functions with discontinuities or requiring large numbers of function evaluations, such as direct search methods, would be better suited for the investigation from this perspective [124].

In addition, the criteria outlined in 5.4.1.2. will also be used in selecting the optimization algorithm, particularly its ease of applicability.

5.7.3. Linear Programming

The linear programming methods described in 5.4.2. would not be suitable for this investigation since both the objective function and the set of constraints must be linear and all coefficients constant.

5.7.4. Non-linear Programming Methods

5.7.4.1. Lagrange Multiplier Method

The Lagrange multiplier method requires partial derivatives as part of its solution process. In order to utilize this method, the partial derivatives at the points at which they are taken must exist.

This method also requires that, after taking the partial derivatives, the resulting expressions be solved simultaneously. The effectiveness of this method can be limited should those partial derivatives be non-linear [125].

The Lagrange function incorporates the original objective function as well as the constraints. In view of this and (5.7.2-1), this method may be difficult to implement due to a possible discontinuity arising depending on whether the battery is charging or discharging.

These requirements would pose difficulties in applying this method to the system being examined.

5.7.4.2. Quadratic Programming

The requirement for linear constraints would eliminate the quadratic programming method described in 5.4.3.2. as a possible optimization method for this investigation [126].

5.7.4.3. Reduced Gradient Method

An algorithm for the general reduced gradient method must determine a feasible direction and an appropriate step size for its search. This necessitates that a set of partial derivatives be calculated from which the reduced gradient is obtained. This requirement can pose some difficulties with regards to expressions such as (5.7.2-1), as mentioned in 5.7.4.1.

An algorithm formulated to use this procedure will require Newton's method as part of its operation. Convergence may not always occur during the phase in which it is used, requiring additional operations, depending upon what caused the failure [127].

These additional evaluations would increase the difficulty in implementing this method. One which requires fewer calculations would be preferable.

5.7.4.4. Penalty Functions

One advantage to using penalty functions is that a constrained problem can be transformed into an unconstrained one.

One of the difficulties with using penalty functions is what value the penalty term weighting term should take [128]. Sufficiently large values can lead to round-off errors and truncations, resulting in a computer program for this algorithm to being unable to produce a solution.

An augmented Lagrangian method can be used to overcome this problem, but determining the weights and Lagrange multipliers, however, can pose some difficulties as the values for the multipliers must be known in order to determine the optimum point.

5.7.5. Dynamic Programming

Dynamic programming is well-suited to staged processes and has been applied to systems involving batteries (see, for example [33], [63], [104]); however, it can be computationally cumbersome, owing to the manner in which the optimum path through the battery during the process is determined. This potential inefficiency could increase if this method is used in successive approximations in multi-variate optimizations.

5.7.6. Luus-Jaakola Direct Search Method

One of the main advantages of the LJ direct search method for solving non-linear optimization problems is its ease of implementation [107] - [110]. Also, since it is a direct search method, no derivatives are required and it is easy to understand and utilize [129].

One disadvantage to a direct search method such as this one is that it can be, in some situations, inefficient with respect to some of the other approaches [129]. There may also be some difficulty in obtaining the global minimum when applying it to staged processes [110].

5.7.7. Stochastic Programming

5.7.7.1. General

A major difficulty with stochastic programming methods is in the formulation of the solution, which is dependent upon the type of problem being investigated and the manner in which the constraints are handled by the method utilized.

5.7.7.2. Recourse Problems

Since recourse problems involve penalty constraints, a number of the constraints given in 5.6. may not be readily incorporated into such a method, if at all. This requires either a re-formulation of the original optimization problem, such as through combining several constraints, or the use of a different method.

5.7.7.3. Stochastic Trees

In stochastic decision trees, dimensionality could potentially be a problem, due to the number of nodes and outcomes of each decision. Determining the optimum path through the tree requires folding back, which could involve an extensive search. In a multi-stage system, subject to the physical and operational constraints given in 5.6., such a search could be computationally inefficient due to the time required to complete the search.

5.7.7.4. Stochastic Dynamic Programming

Stochastic dynamic programming would be subject to the same computational problems mentioned in 5.7.5.

In addition, the introduction of probabilities as part of the process would increase the difficulty of implementing this method in a computer program, as the entire process cannot be determined in advance, unlike conventional dynamic programming.

5.7.7.5. Scenario Aggregation

For multi-stage scenario problems, the decisions can be treated as part of a set of penalty functions. One drawback to this is that the problem becomes more difficult not only to formulate but to solve as each penalty function must be dealt with.

5.7.7.6. Chance Constraint Problems

Chance constraint problems are dependent upon the form of distribution for the random variables. According to [119], much of the theory is based on normal distributions, though selected problems based on other distributions have been examined (see, for example [130]).

5.7.8. Genetic Algorithms

As mentioned in 5.4.8., genetic algorithms are not specifically designed as optimizers, though they can be used as such under some circumstances. The LJ direct search method bases its optimum on the set of variables which yields the best value. In a similar fashion, genetic algorithms used for optimization base their optima on the best-suited individuals produced to date (see Figure 5.4-2).

According to [122], the region in which a global optimum is located can be quickly determined, but the speed with which the actual optimum is found can be slower. Also, there are several ways in which the best-suited individuals can be determined, though, according to some investigators there does not appear to be a consensus on which approach would be best.

Since genetic algorithms are used for modelling systems that evolve with time, they could possibly be better suited for those problems in which the data sets are sequential, rather than being grouped in the manner described in 5.5.

5.7.9. Final Selection

Of the possible optimization methods considered for this investigation, the LJ direct search method was chosen for further development. One of its characteristics is the ease with which it can be implemented in a computer program. In particular, the constraints can be used directly without extensive revisions (if any), which can allow for easy diagnosis should the optimization algorithm fail to converge.

During the early stages of this investigation, a dynamic programming method was formulated and was used as a basis for developing the final optimization algorithm.

5.8. Optimization Algorithm

5.8.1. Symbols

A_W = wind turbine generator rotor area (m^2)
b_F = no-load auxiliary generator fuel consumption rate (L/hr)
C_P = wind turbine generator coefficient of performance
E_0 = internal battery cell voltage (V)
f = auxiliary generator fuel consumption rate (L/hr)
f_{AC} = AC renewable energy operation flag
f_B = battery operation factor
f_C = battery charge flag
f_D = battery discharge flag
f_{DC} = DC renewable energy operation flag

I_B = battery current (A)
K = battery cell polarization coefficient (Ω)
m_F = auxiliary generator fuel consumption rate per unit power ((L/hr)/W)
N_B = number of batteries
N_S = number of photovoltaic modules
P_{B_t} = battery power at time t (W)
P_{G_t} = auxiliary generator output power at time t (W)
P_G^* = required auxiliary generator capacity (W)
$P_{G_t}^*$ = required auxiliary generator output power at time t (W)
$P_{G_{t-1}}^*$ = required auxiliary generator output power at time t - 1 (W)
P_G' = reference auxiliary generator capacity (W)
P_{I_t} = inverter capacity at time t (W)
$P_{I_t}^*$ = required inverter capacity at time t (W)
$P_{I_{t-1}}^*$ = required inverter capacity at time t - 1 (W)
P_{L_t} = load demand at time t (W)
P_{R_t} = rectifier capacity at time t (W)
$P_{R_t}^*$ = required rectifier capacity at time t (W)
$P_{R_{t-1}}^*$ = required rectifier capacity at time t - 1 (W)
P_{S_t} = photovoltaic module output power at time t (W)
P_{W_t} = available wind turbine generator output power per unit area at time t (W/m^2)
Q = instantaneous battery charge (A-hr)
Q_F = final battery charge (A-hr)
Q_{MAX} = maximum battery capacity (A-hr)
Q_{MIN} = minimum battery capacity (A-hr)
Q_0 = initial battery charge (A-hr)
R = battery cell internal resistance (Ω)
V_{B_C} = battery cell voltage (V)
ΔP_{G_t} = increase in required auxiliary generator capacity at time t (W)
ΔP_{I_t} = increase in required inverter capacity at time t (W)
ΔP_{R_t} = increase in required rectifier capacity at time t (W)
ΔP_t = difference between load demand and combined renewable energy output powers at time t (W)
ΔQ = change in battery charge (A-hr)
Δt = time interval (hr)
η_I = inverter efficiency
η_R = rectifier efficiency

5.8.2. Additional Constraints and Conditions

5.8.2.1. General

In addition to the constraints and limits described in 5.7., other conditions are required for the optimization algorithm.

5.8.2.2. Battery Charge/Discharge

In 5.2.4.7., the battery voltage was shown to vary with respect to state of charge. Whether the battery charges or discharges is dependent upon the direction of current flow.

The expression in 5.2.4.7. can be modified by adding the flags given in (5.7.2-1) so that, for a given hour:

$$V_{B_C} = E_0 + \left\{R + K\left[f_C\left(\frac{Q_{MAX}}{Q_{MAX} - Q}\right) + f_D\left(\frac{Q_{MAX}}{Q}\right)\right]\right\}I_B \text{, and} \qquad (5.8.2\text{-}1)$$

$$I_B = \frac{\Delta Q}{\Delta t}, \qquad (5.8.2\text{-}2)$$

with f_C and f_D determined from (5.7.2-1).

5.8.2.3. Renewable Energy Source and Battery Output Powers

According to (5.6.4-1), the load demand is to be primarily met by at least one of the renewable energy sources during a certain time of day, with any excess used for battery charging. For this purpose the optimization algorithm should determine whether this condition exists. Two flags can be incorporated into the algorithm.

During a given time period, the flag for the combination of WTG and batteries is:

$$\left.\begin{aligned} f_{AC} &= \frac{1}{2}\left(1 - \frac{\left|\eta_R A_W C_P P_{W_t} + N_B P_{B_t}\right|}{\eta_R A_W C_P P_{W_t} + N_B P_{B_t}}\right) \\ &= 0, 1 \end{aligned}\right\}, \qquad (5.8.2\text{-}3)$$

while flag for the combination of PV modules and batteries is:

$$\left.\begin{aligned} f_{DC} &= \frac{1}{2}\left(1 - \frac{\left|N_S P_{S_t} + N_B P_{B_t}\right|}{N_S P_{S_t} + N_B P_{B_t}}\right) \\ &= 0, 1 \end{aligned}\right\} \qquad (5.8.2\text{-}4)$$

The value for f_{AC} goes to zero when the power required by the batteries for charging is less than the WTG output power. The value for f_{DC} goes to zero when the battery power required for charging is less than the output power from PV modules.

Should the following condition be true:

$$f_{AC}f_{DC} = 1, \qquad (5.8.2\text{-}5)$$

then the selected combination of A_W, N_S, and N_B is rejected as insufficient power will be available from either the WTG or PV modules.

5.8.2.4. Battery Operational Mode

The direction of power flow in the battery as well as its charge/discharge mode is determined by the following expression:

$$\left.\begin{aligned} f_B &= f_C\left[\frac{f_{DC}}{\eta_R} + \left(1 - f_{DC}\right)\eta_I\right] + f_D\eta_I \\ &= \frac{1}{\eta_R}, \eta_I \end{aligned}\right\}, \qquad (5.8.2\text{-}6)$$

so that, from (5.2.4.6), the power to and from the battery (as seen from the load) is:

$$P_B = f_B V_B I_B \qquad (5.8.2\text{-}5)$$

This accounts for the battery either charging or discharging, and, if charging, whether it is from the AC or DC side.

5.8.2.5. Daytime Operation

The condition given by (5.6.4-1) was the requirement that the load demand be met or exceeded by the renewable energy sources during certain times of the day. This was imposed in order to reduce the dependence upon the auxiliary generator during those times.

It was during the hours that were chosen (from 1000 to 1500 hours) that the output power of the photovoltaic module was at its greatest. This became the basis for imposing this constraint. It was also during that time period that, for most cases, the load demands generally increased, starting at about mid-morning and often reaching a peak towards the middle or late afternoon. This roughly corresponded to the times selected, though the main criterion for selecting these times was the availability of energy.

During the development of the optimization algorithm, other times were examined. During early testing of the algorithm, it was found that extending the times to, say, 0900 to 1600 hours, resulted in more photovoltaic modules being required, which was due to the lower levels of sunlight available during those times. As a result, during mid-day, higher levels of excess (and often unused) power were observed. Reducing the limits to, for example, 1100 to 1400 hours, did not appear to have much influence on the optimization results.

5.8.3. Luus-Jaakola Direct Search Method

5.8.3.1. Optimization Objective

The objective of the optimization is the minimization of the annual capital and operating costs of the system being investigated, subject to the constraints and limits described in 5.6. and 5.8.2.

5.8.3.2. Optimization Overview

The optimum for the overall system was determined in three steps, based on the method described in [110]:

1. obtain an approximate solution using continuous values for A_W, N_S, and N_B,
2. refine the approximate solution using integer values for N_S and N_B, and
3. determine the remaining component capacities based upon the obtained values for A_W, N_S, and N_B.

5.8.3.3. General Optimization Procedure

The general procedure for the optimization method is as follows:

1. set the values for Q_0 and Q_F and the battery charge limits (according to 5.6.3-2),
2. select initial values for A_W, N_S, and N_B,
3. determine the optimum power flow to and from the battery based on the values from Steps 1 and 2,
4. determine the fuel consumption and the capacities of the remaining hardware, and
5. revise the values for A_W, N_S, and N_B and repeat Steps 3 and 4 until a minimum cost is obtained.

This approach is similar to the method of successive approximation used for solving multi-variable dynamic programming problems [101], [102]. For this investigation, the LJ direct search method is used for the optimization.

The results of an application of this method are presented in [131].

The LJ direct search method uses random numbers in its search for a solution, based on initial guesses for A_W, N_S, and N_B. It is therefore possible that the algorithm may yield a solution which is actually a local minimum. Running this method again, using this obtained solution as a starting point, may be necessary to either confirm the obtained solution or determine a different minimum [132].

5.8.3.4. Battery Charge Limits

Prior to optimizing the charge path through the battery, the limits to the battery charge are set in accordance with the constraints given in (5.6.3-2).

5.8.3.5. Battery Optimization

The general LJ direct search method algorithm is described in 5.4.5. For this investigation, the optimum path through the battery during the process (for a given set of A_W, N_S, N_B, and Q_0 and Q_F) is determined as follows:

1. for a given hour, generate a random value for ΔQ as described in 5.4.5.2.,
2. calculate the resulting battery charge and voltage,
3. determine if the constraints and conditions given in 5.6. and 5.7.2. are satisfied,
4. reject the generated ΔQ if any constraints are violated and repeat Steps 1 - 3 until all the constraints satisfied,
5. halt execution if the algorithm fails to converge, and
6. return to Step 1 for the next hour, and repeat Steps 1 - 5 until the end of the process.

5.8.3.6. Initial Continuous-value Solution

The approximate continuous-value solution was obtained in the following manner.

1. select initial values for A_W, N_S, and N_B,
2. obtain the optimum continuous value for A_W, based on the values for N_S and N_B in Step 1 and subject to optimum battery operation as given in 5.8.3.5. and limits on the

value for A_W,

3. determine the upper and lower bounds for A_W based on values from commercially-available WTG's by selecting the nearest sizes above and below the value found in Step 2,
4. set A_W at the upper bound found in Step 3 and determine the optimum continuous value for N_S, based on the value for N_B in Step 1, subject to optimum battery operation and limits on the value for N_S,
5. using the values for A_W and N_S in Step 4, determine the optimum continuous value for N_B, subject to optimum battery operation and limits on the value for N_B,
6. determine the corresponding capacities of the remaining hardware and applicable fuel consumption,
7. calculate the resulting cost,
8. repeat Steps 4 and 5, updating the values for N_S and N_B until these values do not change significantly,
9. set A_W at its lower bound (as determined in Step 3) and repeat Steps 4 - 6, and
10. from the solutions obtained in Steps 8 and 9, select the combination of A_W, N_S, and N_B with the lowest cost as the approximate solution.

5.8.3.7. Required Capacities of Remaining Hardware

The capacities of the auxiliary generator, rectifier, and inverter used for the system are the maximum values for these components required during the duty cycle.

The basis for these calculations is the power difference referred to in 5.6.4.4:

$$\Delta P_t = A_W C_P P_{W_t} + \eta_I N_S P_{S_t} + N_B P_{B_t} - P_{L_t} \qquad (5.8.3\text{-}1)$$

For each hour, the required auxiliary generator capacity is:

$$\left.\begin{aligned} P_{G_t} &= \frac{|\Delta P_t| - \Delta P_t}{2} \\ &= 0 \quad (\Delta P_t \geq 0) \\ &= |\Delta P_t| \quad (\Delta P_t < 0) \end{aligned}\right\} \qquad (5.8.3\text{-}2)$$

The increase in the required auxiliary generator capacity for each hour is:

$$\Delta P_{G_t} = P_{G_t} - P^{\bullet}_{G_{t-1}} \tag{5.8.3-3}$$

The required auxiliary generator capacity is then updated each hour by:

$$P^{\bullet}_{G_t} = P^{\bullet}_{G_{t-1}} + \frac{\left|\Delta P_{G_t}\right| - \Delta P_{G_t}}{2} \tag{5.8.3-4}$$

The second term in (5.8.3-4) goes to zero only when the required auxiliary generator capacity for a given hour is less than the value $P^{\bullet}_{G_t}$ determined up to that time. This allows the algorithm to determine what the maximum required capacity will be throughout the 24-hour process.

Similarly, the required inverter and rectifier output powers for each hour are determined from:

$$\left.\begin{aligned} P^{\bullet}_{I_t} &= P^{\bullet}_{I_{t-1}} + \frac{\left|\Delta P_{I_t}\right| - \Delta P_{I_t}}{2} \\ \Delta P_{I_t} &= P_{I_t} - P^{\bullet}_{I_{t-1}} \\ P_{I_t} &= \eta_I\left(N_S P_{S_t} + f_D V_{B_t} I_{B_t}\right) \end{aligned}\right\}, \text{ and} \tag{5.8.3-5}$$

$$\left.\begin{aligned} P^{\bullet}_{R_t} &= P^{\bullet}_{R_{t-1}} + \frac{\left|\Delta P_{R_t}\right| - \Delta P_{R_t}}{2} \\ \Delta P_{R_t} &= P_{R_t} - P^{\bullet}_{R_{t-1}} \\ P_{R_t} &= \eta_R\left(-f_C f_{DC} f_B V_{B_t} I_{B_t}\right) \end{aligned}\right\} \tag{5.8.3-6}$$

The minus sign for P_{R_t} in (5.8.3-6) accounts for the battery charging, during which the current is taken as negative.

5.8.3.8. Fuel Consumption

For each hour, the fuel consumption is:

$$\left.\begin{aligned} f &= \frac{\left|P_{G_t}\right|}{P_{G_t}}\left(m_f P_{G_t} + b_f\right)\left(\frac{P_G^{\bullet}}{P_G'}\right)\Delta t \quad \left(P_{G_t} > 0\right) \\ &= 0 \qquad\qquad\qquad\qquad\qquad\quad . \left(P_{G_t} = 0\right) \end{aligned}\right\} \qquad (5.8.3\text{-}7)$$

5.8.3.9. Final System Cost Based on Continuous Values

The final system cost includes the costs for the maximum capacities calculated from (5.8.3-1) - (5.8.3-6) and the cost of the total fuel consumption calculated from (5.8.3-7).

5.8.3.10. Solution Based on Integer Values

The values for N_S and N_B obtained in 5.8.3.6. are adjusted by the following procedure:

1. truncate the values for N_S and N_B found in Step 10 in 5.8.3.6. to their lower integer values, initialize a base value to be used for comparison, and use the set of A_W, N_S, and N_B as the base solution,

2. determine the objective function value using the values for N_S and N_B from Step 1,

3. reset the base value to the objective function value found in Step 2 if the latter is lower, and set the base solution to the corresponding A_W, N_S and N_B,

4. increment N_S and repeat Steps 2 and 3,

5. increment N_B and repeat Steps 2 - 4, and

6. select the combination of A_W, N_S, and N_B which gives the lowest objective function value as the optimum solution.

The required capacities of the auxiliary generator, inverter, and rectifier and fuel consumption were determined as outlined in 5.8.3.7. and 5.8.3.8, respectively.

5.8.3.11. Final System Cost Based on Integer Values

The final system cost was determined by:

- calculating the cost of the required WTG area and number of PV modules and batteries,

- rounding the capacities for the auxiliary generator, inverter, and rectifier to their respective nearest higher values and determining the corresponding costs, and

- determining the applicable maintenance costs.

5.8.4. Dynamic Programming

5.8.4.1. General Procedure

Early in this investigation, a multi-pass dynamic programming was formulated and used in part for developing the method described in 5.8.3. Specifically, it was used to determine the optimum path through the batteries, as outlined in 5.4.5.2.

This method consisted of five major steps:

1. setting the battery charge limits,
2. laying out a coarse grid inside the charge envelope (consisting of several charge levels at the end of each time interval), and determining the optimum path through the battery based on that grid,
3. reducing both the time and charge intervals of the grid and determining a new optimum path,
4. reducing both the time and charge intervals of the grid until the time interval was as small as possible (i. e., one hour), repeating Step 3 each time the grid is modified, and
5. reducing the charge interval only and determining a new optimum path each time until convergence.

The battery charge limits were set in the same manner as given in 5.8.3.4.

5.8.4.2. Path Determination

Each point on the grid mentioned in 5.8.4.1. potentially lies on the optimum path. Multiple paths through the grid are therefore possible as several battery charge levels exist at the end of each time interval.

The optimum path is found by first determining which of those possible paths may qualify. Each charge level at the end of each time interval can be reached from each charge level at the end of the previous time interval. The dynamic programming algorithm determines which of those previous points should be considered.

This is shown in Figure 5.8-1.

At the end of the process, the path with the optimum value is chosen, and the algorithm moves sequentially backwards to the initial charge to determine which points would lie on it.

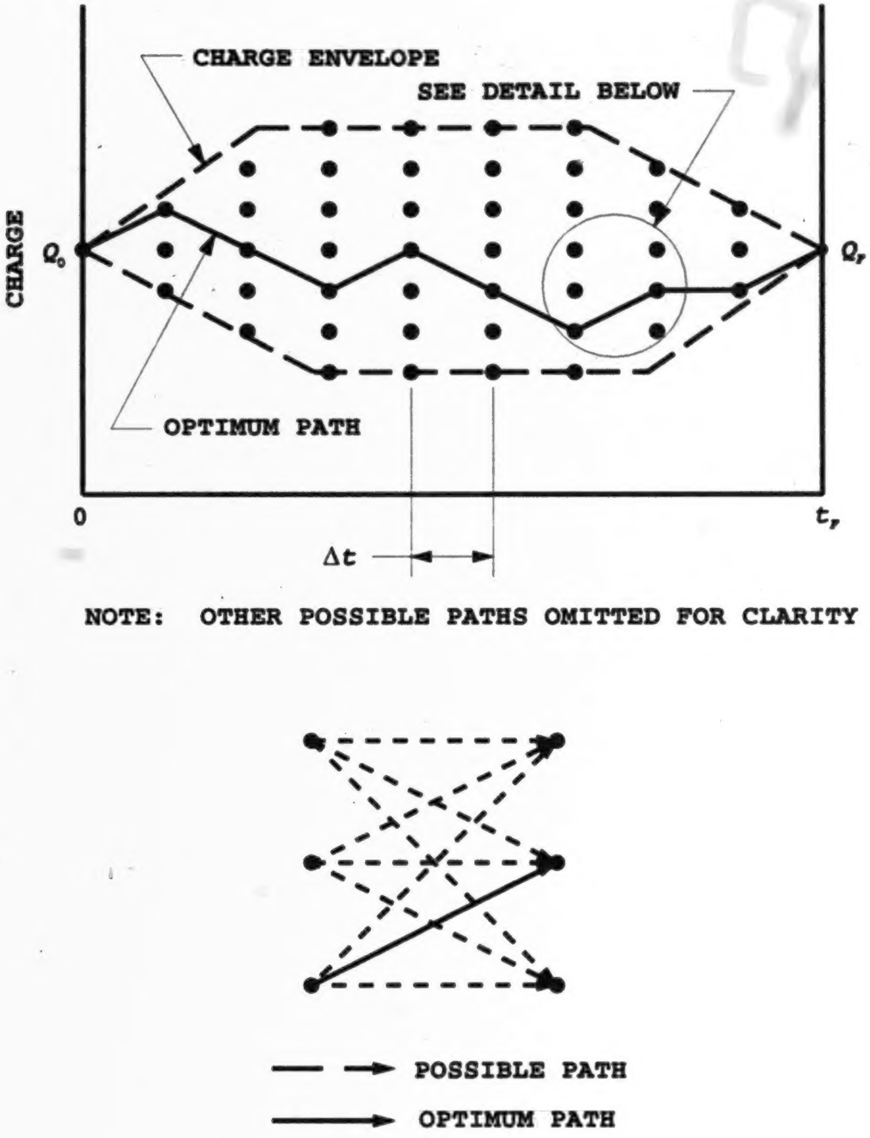
5.9. Economic Considerations

5.9.1. Symbols

c_A = annualized capital cost factor
C_B = annualized battery cost (\$/battery)
c_B = battery cost (\$/A-hr/battery)
C_F = annualized fuel cost (\$/L)
c_F = fuel cost (\$/L)
C_G = annualized auxiliary generator cost (\$/W)
c_G = auxiliary generator cost (\$/W)
C_I = annualized inverter cost (\$/W)
c_I = inverter cost (\$/W)
C_{MG} = annualized auxiliary generator maintenance cost (\$/W-hr)
c_{MO} = annualized maintenance and operating cost factor
C_{MW} = annualized wind turbine generator maintenance cost (\$/W-hr)-m^2
C_R = annualized rectifier cost (\$/W)
c_R = rectifier cost (\$/W)
C_S = annualized photovoltaic module cost (\$/module)
c_S = photovoltaic module cost (\$/module)
c_w = wind turbine cost (\$/m^2)
C_w = annualized wind turbine cost (\$/m^2)
g_R = number of auxiliary generator replacements during system lifetime
i = hour index
= interest rate
i_I = inflation rate
n = system lifetime (yr)
n_{GR} = auxiliary generator replacement time (yr)
n_R = remaining lifetime for auxiliary generator at end of system life (yr)
Q_{MAX} = maximum battery capacity (A-hr)
S = salvage fraction
t_{G_i} = auxiliary generator operating time during *i*-th hour of day (hr)
t_{GS_i} = auxiliary generator operating time during *i*-th hour of summer day (hr)
t_{GW_i} = auxiliary generator operating time during *i*-th hour of winter day (hr)
$\delta(n_R)$ = unit impulse function

5.9.2. General

The total annualized cost of the system consists of annualized


CHARGE ENVELOPE
SEE DETAIL BELOW
CHARGE
Q_0
Q_r
OPTIMUM PATH
0
t_r
Δt
POSSIBLE PATH
OPTIMUM PATH

NOTE: OTHER POSSIBLE PATHS OMITTED FOR CLARITY

Figure 5.8-1. Dynamic Programming Path Through Battery

capital costs and operating and maintenance expenses. These costs are subject to interest and inflation rates. For this investigation, it is assumed that the capital expenses were for money borrowed to purchase the hardware.

5.9.3. Interest and Inflation Rates

5.9.3.1. Interest Rate

The interest rate used in this investigation was assumed to be at 10% per annum, which is typical of values available from lenders as of December 1999 [133] - [135]. Interest rates for loans vary due to a number of factors, depending upon the risk involved, the borrower's circumstances, and the prime lending rate set by the Bank of Canada. These rates are often in effect for only a few years and then re-negotiated.

5.9.3.2. Inflation

The average Canada-wide inflation rate for 1989 - 1999 is estimated to be approximately 3% [136]. Price increases vary with respect to both the commodities in question and geographical region.

5.9.4. Annualized Capital and Maintenance Costs

5.9.4.1. Annualized Capital Costs

Annualized capital costs for the hardware are determined using the expression for the uniform worth of a present sum (allowing for salvage) [35], [36], [137]:

$$c_A = \left[(1.0 - S)\frac{i(1 + i)^n}{(1 + i)^n - 1} + Si\right] \qquad (5.9.4\text{-}1)$$

It is assumed that at the end of the life of the system, the hardware has some salvage value with S assumed to be 10%.

5.9.4.2. Annualized Maintenance and Operating Costs

Annualized maintenance costs for the hardware and system operating costs are determined using the factor [137], [138]:

$$c_{MO} = \frac{i_I(1 + i_I)^n}{(1 + i_I)^n - 1} \qquad (5.9.4\text{-}2)$$

5.9.5. Component Replacement

5.9.5.1. General

Replacement of some system components is considered in the cost estimate. In particular, the auxiliary generator and batteries are assumed to have lifetimes less than that of the overall system itself.

5.9.5.2. Auxiliary Generator

The estimated lifetime of a typical auxiliary generator is approximately 15000 - 20000 operating hours [139]. For this investigation, it is assumed to be two cumulative operating years (17520 hours).

For a given system, the auxiliary generator replacement time (in years) is:

$$\left.\begin{aligned} n_{GR} &= \frac{2}{\dfrac{\sum_{i=1}^{24} t_{G_i}}{24}} && \text{(total)} \\ &= \frac{2}{\left(\dfrac{1}{365}\right)\left(\dfrac{186\sum_{i=1}^{24} t_{GS_i}}{24} + \dfrac{179\sum_{i=1}^{24} t_{GW_i}}{24}\right)} && \text{(seasonal)} \end{aligned}\right\} \quad \ldots\ldots \text{(5.9.5-1)}$$

Since the auxiliary generator is to be replaced every two cumulative years, at the end of the system lifetime, the auxiliary generator in place may have some life remaining. This remaining lifetime is (in years):

$$n_R = n \bmod(n_{GR}) \quad \ldots\ldots \text{(5.9.5-2)}$$

The number of times during the system's life that the auxiliary generator is replaced is given by:

$$\left.\begin{aligned} g_R &= \frac{n - n_R}{n_{GR}} - \delta(n_R) \\ \delta(n_R) &= 0 \quad (n_R \neq 0) \\ &= 1 \quad (n_R = 0) \end{aligned}\right\} \quad \ldots\ldots \text{(5.9.5-3)}$$

This allows for the fact that the auxiliary generator may not need to be replaced at the end of the system's operating life.

5.9.5.3. Batteries

Several manufacturers produce batteries which are warrantied up to ten years. Often, warranties apply only for certain conditions of service. When these conditions are exceeded, the lifetimes of the batteries can be reduced.

For this investigation, the lifetime of the batteries is assumed to be five years. This accounts for reductions in lifetime due to such factors as adverse weather and extended periods of deep discharge which would exceed the conditions for which the batteries are designed and warrantied.

5.9.6. Component Maintenance

5.9.6.1. General

Equipment is maintained in accordance with applicable procedures, schedules, and maintenance programs [140]. These programs account for such aspects as equipment availability (i. e., whether the equipment in question can be shut down on occasion) and the location and availability of spare parts. An example of the guidelines for a maintenance program can be found in [141].

5.9.6.2. Wind Turbine Generator Maintenance Costs

According to [142], the maintenance cost for a large wind farm is estimated to be about \$0.01/kWh. Another estimated value is given in [143], which suggests 2 - 3% of the capital cost for annual maintenance and insurance.

Large companies such as electric power utilities often implement maintenance programs which involve the use of trained personnel and standardized procedures. For this investigation, a formal maintenance program is not assumed to be in effect, resulting in higher costs.

Details on what typically is required in WTG maintenance are given in [144] and [145]. Because WTG's are often mounted on top of support towers, the generator site itself must be prepared prior to the actual maintenance. This involves the use of appropriate climbing and safety equipment and at least two people would be required for this task. Maintaining the WTG includes lubrication of drive train components and inspection of the blades and tower.

For this investigation, the maintenance is estimated to be about $0.033/kWh, which accounts for the required safety equipment, additional personnel required for servicing the WTG. An additional allowance for unplanned maintenance costs was also made [146].

5.9.6.3. Auxiliary Generator Maintenance Costs

An example of the routine maintenance required for a diesel genset is given in [147]. This includes the replacement of oil and filters. Intervals of 300 hours are recommended for the lubricant, with 1500 hours as the limit.

For this investigation, the maintenance costs for the auxiliary generator are estimated at $0.01/kWh, which is the cost for a 20 kW genset (continuous operation). This is similar to the estimate given in [146].

5.9.6.4. Reserve Auxiliary Generator

In addition, the system will be designed for two identical auxiliary generators with one being the primary generator and the other one held in reserve for when the primary unit is being serviced. This would ensure uninterrupted power for the load.

5.9.7. Fuel

The cost of the total fuel required throughout the system lifetime is annualized based on inflation.

5.9.8. Annualized Costs

5.9.8.1. Present Costs

The costs for the following items are shown in Table 5.9-1. and are typical of market values for the period from mid-1998 to mid-1999.

5.9.8.2. Wind Turbine Generator

The annualized capital cost per unit area for the wind turbine generator is:

$$C_W = c_A c_W \qquad (5.9.8\text{-}1)$$

5.9.8.3. Photovoltaic Modules

The annualized capital cost per module for the photovoltaic modules is:

Table 5.9-1. System Costs

Cost	Value
c_W	$800/m^2
c_S	$500/module
c_G	$1.00/W
c_F	$0.45/L
c_B	$2.50/(A-hr/battery)
c_I	$1.00/W
c_{R_c}	$1.00/W
i	10%
i_I	3%
n	20 years
S	10%

$$C_S = c_A c_S \qquad (5.9.8\text{-}2)$$

5.9.8.4. Auxiliary Generator

The annualized capital cost per watt for the auxiliary generator is:

$$C_G = c_A c_G (2 + g_R). \qquad (5.9.8\text{-}3)$$

This expression accounts for a primary and secondary generator, as mentioned in 5.9.6. In addition, the cost of any replacement generators required during the system lifetime are initially approximated as capital expenses prior to determining the annual payments.

5.9.8.5. Batteries

The annualized capital cost per unit for the batteries is:

$$C_B = 4Q_{MAX} c_A c_B \qquad (5.9.8\text{-}4)$$

This value is based on the costs of any replacement batteries required during the system lifetime as capital expenses before the annual payments are determined. The factor of 4 accounts for the batteries lasting 5 years during the 20-year lifetime of the system.

5.9.8.6. Inverter and Rectifier

The annualized capital costs per watt for the inverter and rectifier are, respectively:

$$C_I = c_A c_I, \text{ and} \qquad (5.9.8\text{-}5)$$

$$C_R = c_A c_R \qquad (5.9.8\text{-}6)$$

5.9.8.7. Maintenance

The annualized maintenance cost per kilowatt-hr for the wind turbine generator is:

$$C_{MW} = (7300)\left(\frac{0.033}{1000}\right) c_I A_W, \qquad (5.9.8\text{-}7)$$

while that for the auxiliary generator is:

$$C_{MG} = (7300)\left(\frac{0.01}{1000}\right)c_I \quad (5.9.8\text{-}8)$$

The entire value of the maintenance throughout the system lifetime is initially approximated as a total cost before determining the annual payments. The value of 7300 is the number of days in the 20-year system lifetime, with 1000 representing 1000 W-hours.

5.9.8.8. Fuel

The annualized cost for the fuel is:

$$C_F = (7300)c_I c_F \quad (5.9.8\text{-}9)$$

The entire expense for the fuel required by the auxiliary generator throughout the system lifetime is initially approximated as a total cost before determining the annual payments.

5.9.9. Financial Assistance

The costs of the system as designed can be reduced by several means.

One is the reduction of fuel costs through programs such the Alberta Farm Fuel Benefit in which the diesel fuel is not subjected to certain taxes when used for agricultural purposes [148]. Another such program is the former Accelerated Capital Cost Allowance, available through Environment Canada, in which the cost of equipment used for reducing pollution could be written off for depreciation purposes within three years [148].

Other similar financial incentives are available, though these are dependent upon the end use for the money, such as farm equipment purchases or farm improvement.

5.10. Objective Function

5.10.1. Symbols

A_W = wind turbine generator rotor area (m^2)
C_B = annualized battery cost (\$/battery)
c_B = battery cost (\$/A-hr/battery)
C_F = annualized fuel cost (\$/L)
C_G = annualized auxiliary generator cost (\$/W)
C_I = annualized inverter cost (\$/W)
C_{MG} = annualized auxiliary generator maintenance cost (\$/W-hr)
C_{MW} = annualized wind turbine generator maintenance cost (\$/W-hr)-m^2

C_P = wind turbine generator coefficient of performance
C_R = annualized rectifier cost (\$/W)
C_S = annualized photovoltaic module cost (\$/module)
C_W = annualized wind turbine cost (\$/m^2)
f_i = auxiliary generator fuel consumption rate during i-th hour of day (L/hr)
f_{S_i} = auxiliary generator fuel consumption rate during i-th hour of summer day (L/hr)
f_{W_i} = auxiliary generator fuel consumption rate during i-th hour of winter day (L/hr)
i = hour index
N_B = number of batteries
N_S = number of photovoltaic modules
P_G^* = required auxiliary generator capacity (W)
P_{G_i} = auxiliary generator output power during i-th hour of day (W)
P_{GS_i} = auxiliary generator output power during i-th hour of summer day (W)
P_{GW_i} = auxiliary generator output power during i-th hour of winter day (W)
P_I = inverter capacity (W)
P_R = rectifier capacity (W)
P_{WS_i} = available wind turbine generator output power per unit area during i-th hour of summer day (W/m^2)
P_{WW_i} = available wind turbine generator output power per unit area during i-th hour of winter day (W/m^2)
Δt = time interval (hr)

5.10.2. Functions

When both summer and winter data are combined, the objective function is:

$$\left.\begin{aligned} &C_W A_W + C_S N_S + C_B N_B + C_G P_G^* + C_I P_I + C_R P_R \\ &+ C_F \sum_{i=1}^{24} f_i \Delta t + C_{MG} \sum_{i=1}^{24} P_{G_i} \Delta t + C_{MW} \sum_{i=1}^{24} C_P P_{W_i} \Delta t \end{aligned}\right\} \cdots\cdots\cdots\cdots \text{(5.10.1-1)}$$

When seasonal effects were taken into account, the objective function was modified to:

$$\left.\begin{aligned} &C_W A_W + C_S N_S + C_B N_B + C_G P_G^* + C_I P_I + C_R P_R \\ &+ C_F \left[\left(\frac{186}{365}\right) \sum_{i=1}^{24} f_{S_i} + \left(\frac{179}{365}\right) \sum_{i=1}^{24} f_{W_i} \right] \Delta t \\ &+ C_{MG} \left[\left(\frac{186}{365}\right) \sum_{i=1}^{24} P_{GS_i} \Delta t + \left(\frac{179}{365}\right) \sum_{i=1}^{24} P_{GW_i} \Delta t \right] \\ &+ C_{MW} \left[\left(\frac{186}{365}\right) \sum_{i=1}^{24} C_P P_{WS_i} \Delta t + \left(\frac{179}{365}\right) \sum_{i=1}^{24} C_P P_{WW_i} \Delta t \right] \end{aligned}\right\} \cdots\cdots\cdots\cdots \text{(5.10.1-2)}$$

These expressions are for the capital costs of the components, the fuel required, and the maintenance for the auxiliary generator and WTG. The seasonal summations are weighted to account for the length of the summer and winter seasons.

The algorithm described in 5.8. was used to optimize this expression.

5.11. Previous Work by Author

5.11.1. Optimum Rated Wind Speeds

Earlier in this investigation, optimum rated wind speeds for a WTG were investigated in [149], based on work described in [48] and using weather data for the Edmonton region. It was noted that these values had both daily and seasonal variations, ranging from about 35 km/hr to nearly 50 km/hr. This corresponds to the rated WTG speeds used by a number of manufacturers.

5.11.2. Mixed-integer Linear Programming

Prior to the work described in [131], the optimization of a system by means of a mixed-integer linear programming algorithm was examined [150], [151]. The models that were developed were limited in its applicability as they were based on a fixed voltage for the battery, used a simpler method for calculating the fuel consumption, and did not include maintenance costs.

Both of optimization models for [131] and [150], [151] were found to have similar WTG areas, though the ones described in [150], [151] had different requirements for the PV modules and batteries.

5.12. System Parameters

5.12.1. Symbols

A_W = wind turbine generator rotor area (m^2)
b_F = no-load auxiliary generator fuel consumption rate (L/hr)
C_p = wind turbine generator coefficient of performance
I_{MP} = photovoltaic module maximum power point current (A)
I_{SC} = photovoltaic module short-circuit current (A)
k = temperature insolation change coefficient (°C/(W/m^2))
K = battery cell polarization coefficient (Ω)
m_F = auxiliary generator fuel consumption rate per unit power ((L/hr)/W)
P'_G = reference auxiliary generator capacity (W)
Q_{MAX} = maximum battery capacity (A-hr)

Q_{MIN} = minimum battery capacity (A-hr)
Q_0 = initial battery charge (A-hr)
R = battery cell internal resistance (Ω)
R_S = photovoltaic module series resistance (Ω)
S_{REF} = reference irradiance (W/m^2)
T_{REF} = photovoltaic module reference temperature (°C)
v_{CI} = wind turbine generator cut-in wind speed (m/s, km/hr)
v_{CO} = wind turbine generator cut-out wind speed (m/s, km/hr)
v_R = wind turbine generator rated wind speed (m/s, km/hr)
V_{MP} = photovoltaic cell maximum power point voltage (V)
V_{OC} = photovoltaic module open-circuit voltage (V)
α = photovoltaic current temperature change coefficient (A/°C)
β = photovoltaic voltage temperature change coefficient (V/°C)
η_I = inverter efficiency
η_R = rectifier efficiency
ρ_R = rated air density (kg/m^3)

5.12.2. Parameters

The system parameters used for this investigation are outlined in Table 5.12-1. Two different types of WTG were considered, with the one best utilizing the local wind distribution at the site in question being used for the optimization. This can be determined by examining the wind speed histogram and comparing the distribution with the cut-in speeds.

5.13. Optimization Algorithm Parameters

5.13.1. Symbols

A_W = wind turbine generator rotor area (m^2)
n_P = number of optimization passes for battery
N_B = number of batteries
$N_{B_{MAX}}$ = maximum number of batteries
N_S = number of photovoltaic modules
$N_{S_{MAX}}$ = maximum number of photovoltaic modules
Q_{L_t} = minimum allowed battery charge at time t (A-hr)
Q_{U_t} = maximum allowed battery charge at time t (A-hr)
$r_{\Delta Q_t}$ = initial range for ΔQ_t (A-hr)
x_0 = range reduction parameter
ΔQ = change in battery charge (A-hr)
ΔQ_t = change in battery charge at time t (A-hr)
η = Luus-Jaakola search method optimization range reduction factor

5.13.2. Description

The optimization algorithm used for this investigation was described in 5.8.3. The optimization itself is accomplished through two loops: the inner loop is for the trajectory

Table 5.12-1. Hardware Parameters

Parameter	Value
Small-capacity WTG	
v_R	45 km/hr [152]
v_{CI}	10 km/hr [152]
v_{CO}	202.5 km/hr
C_P	0.3 [50]
ρ_R	1.228 kg/m^3 [153], [154]
A_W	1.0387 m^2 [152]
Large-capacity WTG	
v_R	40 km/hr [149]
v_{CI}	12 km/hr [149] - [151]
v_{CO}	120 km/hr [149] - [151]
C_P	0.3 [50]
ρ_R	1.228 kg/m^3 [153], [154]
A_W	49.32 m^2 [155]
Photovoltaic Module	
T_{REF} (ambient)	25°C [44]
S_{REF}	1000 W/m^2 [44]
PV module rated peak power	35 W [44]

Table 5.12-1. System Parameters (Cont'd)

Parameter	Value
Photovoltaic Module (Cont'd)	
V_{MP} (rated peak conditions)	15.5 V [44]
I_{MP} (rated peak conditions)	2.26 A [44]
R_S	0.568 Ω [44], [45]
k	0.0263 °C/(W/m^2) [44]
α	0.0 [44]
β	-0.090 V/°C [44]
Battery	
Q_{MAX}	100 A-hr
Q_{MIN}	20 A-hr
Q_0	60 A-hr
Maximum battery charge rate	*c*/10 [123]
Maximum battery discharge rate	*c*/20 [123]
R	-0.0150 Ω [63], [64]
k	0.0189 Ω [63], [64]
Auxiliary Generator	
b_F	0.871 L/hr [72]
m_F	368 x 10^{-6} L/hr/W [72]
P'_G	7000 W [72]

Table 5.12-1. System Parameters (Cont'd)

Parameter	Value
Inverter and Rectifier	
η_I	90%
η_R	90%

through the battery during the process and the outer loop for the renewable energy source capacities.

5.13.3. Battery Operation

A multi-pass optimization algorithm for the battery trajectory was formulated, based on [107] - [109]. The general LJ direct search method described in [107], [108] was modified using information in [109].

In this part of the optimization, the variable being optimized was the change in the battery charge for each hour (ΔQ_t) of the process. A flowchart for this part is shown in Figure 5.13-1. During the operations for the inner loop, the range for ΔQ_t was adjusted in accordance with (5.4.5-2).

These operations are repeated in a series of passes in which the initial value for the range of ΔQ_t for each inner loop is subsequently reduced in size. For the first few passes in the outer loop, the range is adjusted by:

$$\eta^{n_p} r_{\Delta Q_t}, \qquad (5.13.2\text{-}1)$$

while after the required number of loops (i. e., the breakpoint), it is changed by:

$$|x_0 - \Delta Q_t| \qquad (5.13.2\text{-}2)$$

5.13.4. Renewable Energy Source Optimization

A flowchart of the renewable energy source optimization method is shown in Figure 5.13-2.

5.13.5. Optimization Parameters

Each of the algorithms illustrated by Figures 5.13-1 and 5.13-2 requires several computational loops and adjustments to the applicable ranges. No specific method for determining the required number of loops, the ranges, and the corresponding reduction factors was presented in [107] - [109]. These values appear to be specific to the optimization problem being considered and are determined accordingly by the investigator.

Several factors can influence the selection of these values, such as the execution time of the algorithm and the speed of convergence for the solution. These can often be best determined by trial and error, depending upon the problem under consideration and the investigator's judgement and understanding of the problem itself.

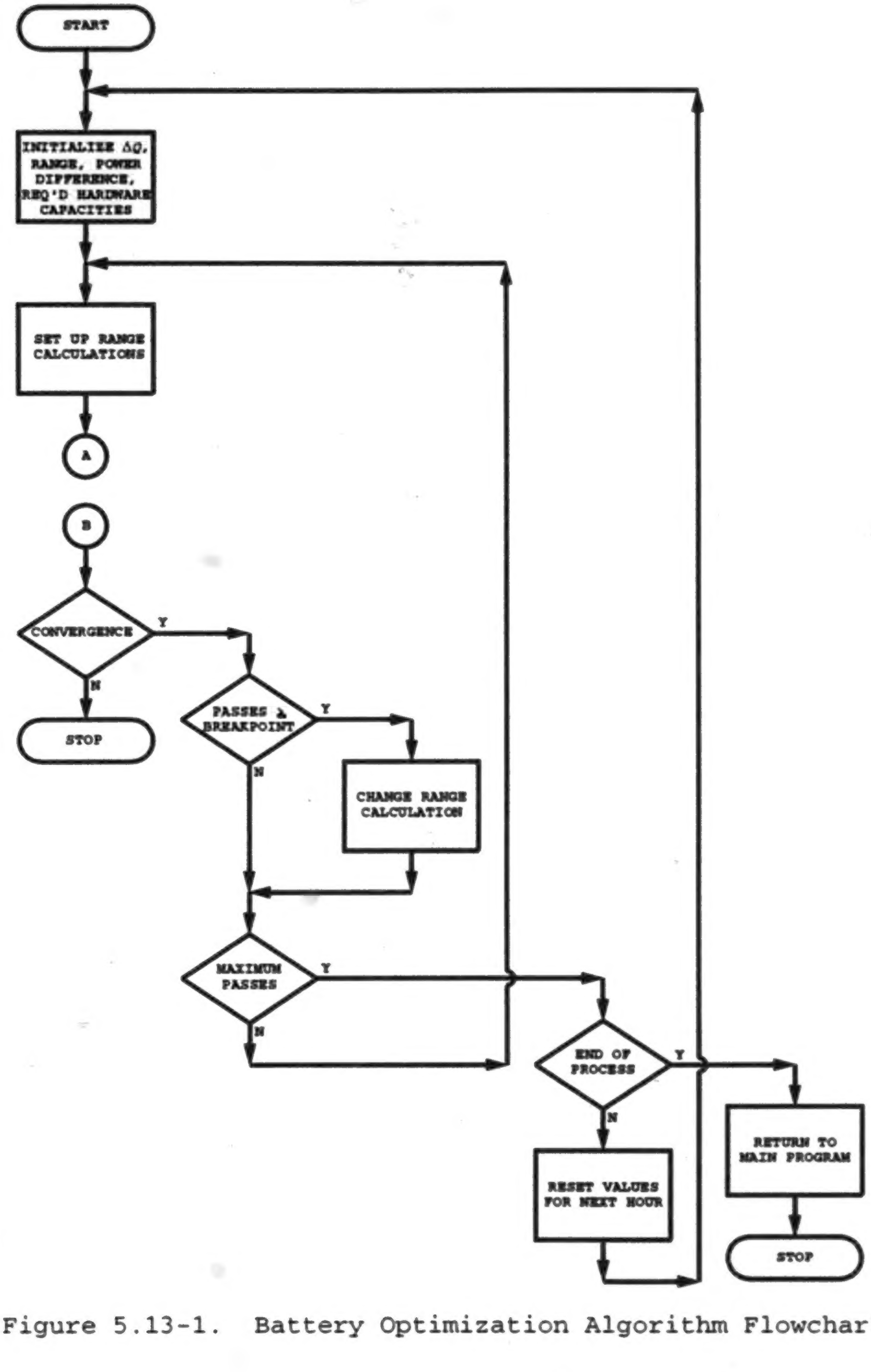

START
INITIALIZE ΔQ, RANGE, POWER DIFFERENCE, REQ'D HARDWARE CAPACITIES
SET UP RANGE CALCULATIONS
A
B
CONVERGENCE
Y
N
STOP
PASSES ≥ BREAKPOINT
Y
N
CHANGE RANGE CALCULATION
MAXIMUM PASSES
Y
N
END OF PROCESS
Y
N
RESET VALUES FOR NEXT HOUR
RETURN TO MAIN PROGRAM
STOP

Figure 5.13-1. Battery Optimization Algorithm Flowchart

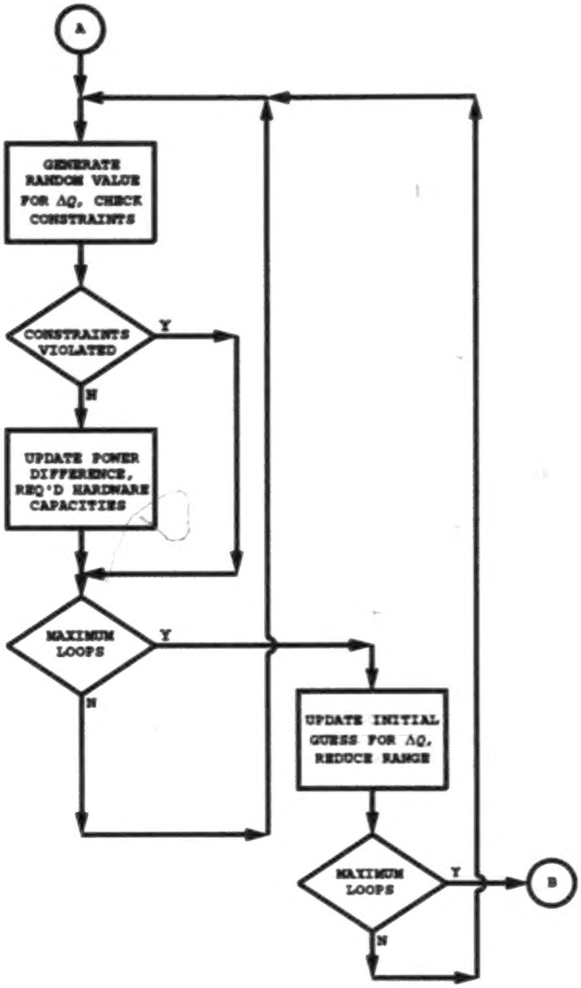

A
GENERATE RANDOM VALUE FOR ΔQ, CHECK CONSTRAINTS
CONSTRAINTS VIOLATED
Y
N
UPDATE POWER DIFFERENCE, REQ'D HARDWARE CAPACITIES
MAXIMUM LOOPS
Y
N
UPDATE INITIAL GUESS FOR ΔQ, REDUCE RANGE
MAXIMUM LOOPS
Y
N
B

Figure 5.13-1. Battery Optimization Algorithm Flowchart (Cont'd)

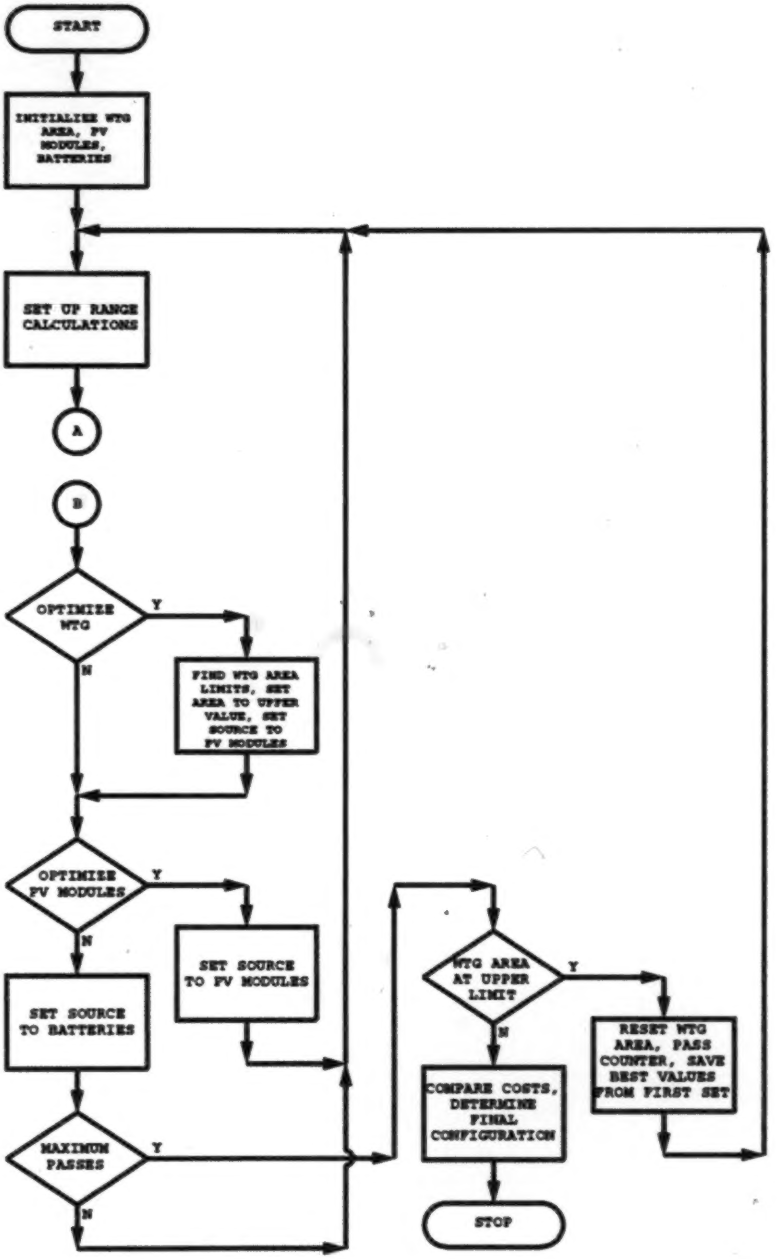

START
INITIALIZE WTG AREA, PV MODULES, BATTERIES
SET UP RANGE CALCULATIONS
A
B
OPTIMIZE WTG
Y
N
FIND WTG AREA LIMITS, SET AREA TO UPPER VALUE, SET SOURCE TO PV MODULES
OPTIMIZE PV MODULES
Y
N
SET SOURCE TO PV MODULES
SET SOURCE TO BATTERIES
MAXIMUM PASSES
Y
N
WTG AREA AT UPPER LIMIT
Y
N
RESET WTG AREA, PASS COUNTER, SAVE BEST VALUES FROM FIRST SET
COMPARE COSTS, DETERMINE FINAL CONFIGURATION
STOP

Figure 5.13-2. Renewable Energy Source Optimization Algorithm Flowchart

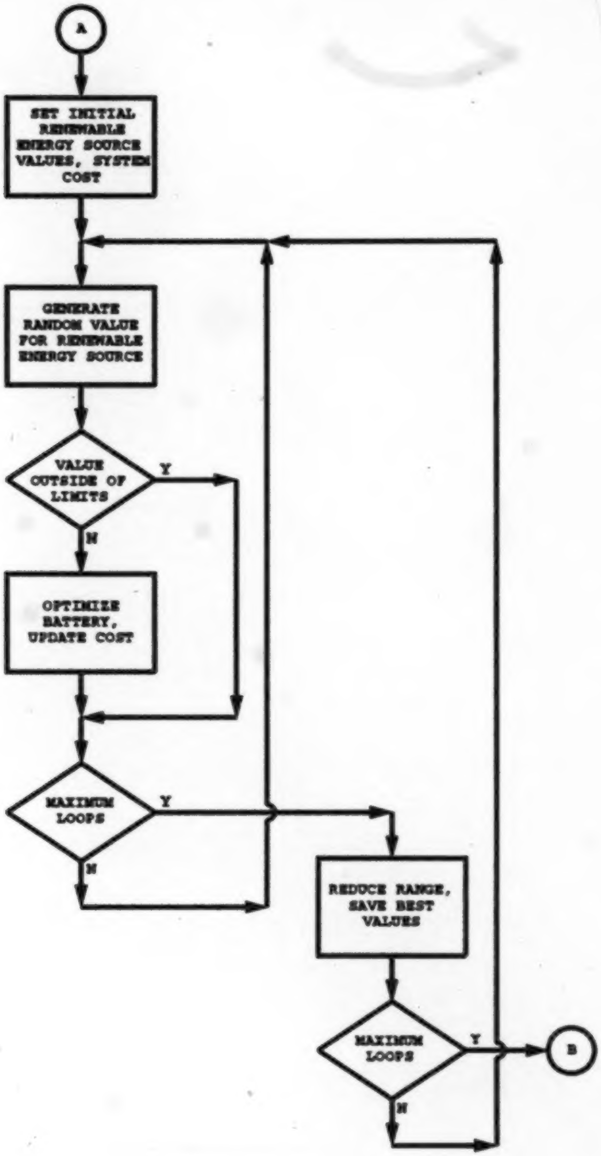

A
SET INITIAL RENEWABLE ENERGY SOURCE VALUES, SYSTEM COST
GENERATE RANDOM VALUE FOR RENEWABLE ENERGY SOURCE
VALUE OUTSIDE OF LIMITS
Y
N
OPTIMIZE BATTERY, UPDATE COST
MAXIMUM LOOPS
Y
N
REDUCE RANGE, SAVE BEST VALUES
MAXIMUM LOOPS
Y
N
B

Figure 5.13-2. Renewable Energy Source Optimization Algorithm Flowchart (Cont'd)

During the development of the algorithm used for this investigation, extensive testing was conducted for various combinations of numbers of loops and variable ranges. The values that were subsequently used are given in Table 5.13-1.

It should be noted that since this optimization method is based upon the generation of random numbers by a computer, execution times can vary between successive runs for the same problem and constraints.

5.13.6. Optimization Starting Points

One factor which can influence the speed by which a solution is obtained is the starting point for the variables being optimized. Prior to starting an optimization, suitable initial values are required, though this is dependent upon the investigator's judgement and knowledge of the problem being examined [107] - [109].

Because of this, it is advisable to check whether the results from an optimization run represent a local extremum. To accomplish this, another run should be made to check these results [132]. The starting point for this new run should, where possible, be the obtained results. In some cases, however, if the results are very close to the allowed limits, a nearby point (not necessarily feasible) should be used instead to allow the optimization algorithm to function.

Should the algorithm confirm the previous results, the point is either the required minimum or a very deep local extremum.

5.13.7. Initial Battery State of Charge

The optimization of the system is dependent upon the initial SOC of the battery. Test results indicated that this value should be set at 60% of the maximum capacity. This value was chosen as it is midway between maximum and minimum allowable SOC and allows the system to utilize the available charge throughout the process, reaching its minimum during the early morning when the available renewable energy is the least.

Starting the process with a much higher initial SOC, it was noted that most of the battery charge was unused, so that the available capacity was under-utilized. This would indicate that the battery would be an unnecessary expense as the unused capacity would not contribute to the system operation.

If the process was started with a much lower SOC, it was found that the battery remains at the lower charge levels and is ineffective as a power source. Again, this would mean that the battery would not be required.

Table 5.13-2. Optimization Algorithm Parameters

Parameter	Value
Number of inner battery loops	5
Number of outer battery loops	20
Total number of battery passes	10
Battery pass breakpoint	5
Number of inner hardware loops	10
Number of outer hardware loops	10
Number of A_W passes	1
Number of N_S passes	2
Number of N_B passes	2
Initial A_W range	Maximum A_W
Initial N_S range	$0.5\ N_{S_{MAX}}$*
Initial N_B range	$0.5\ N_{B_{MAX}}$*
ΔQ_t	$Q_{U_t} - Q_{L_t}$
ε	0.95
η	0.70

* Unless specified otherwise

5.14. Comparison with Dynamic Programming

5.14.1. Symbols

A_W = wind turbine generator rotor area (m^2)
N_B = number of batteries
N_S = number of photovoltaic modules
v_{CI} = wind turbine generator cut-in wind speed (m/s, km/hr)
v_{CO} = wind turbine generator cut-out wind speed (m/s, km/hr)
v_R = wind turbine generator rated wind speed (m/s, km/hr)

5.14.2. General

From 5.8.2., 5.8.3. and 5.13., it can be seen that the most complex part of the optimization algorithm was that for the battery.

Earlier in the investigation, a dynamic programming algorithm for optimizing the trajectory through the battery was formulated. The basis for this algorithm was described in 5.8.4. This can be used as a comparison with the LJ method

5.14.3. Test Data

Data and results from two optimization runs conducted earlier during the investigation for the final algorithm were also used for this test. These are presented in Table 5.14-1.

For these tests, the mean values for the WTG power/area, PV module output power, and load demand for Edmonton Load 1 were used as input data.

5.14.4. Comparison of Results

Results from the tests run using the data given in 5.14.2. are shown in Figures 5.14-1 and 5.14-2. In both cases, there is little correspondence between the two methods between 0200 to 1100 hours, though the difference becomes smaller later on, especially in Figure 5.14-1. This indicates that a renewable energy system using the LJ method would depend less on the auxiliary generator, as the system would make greater use of stored energy, particularly in the morning.

The results from both methods, though, show the same general behaviour.

5.14.5. Interpretation of Results

In interpreting the results from Figures 5.14-1 and 5.14-2, a number of differences between the two methods should be emphasized.

Table 5.14-1. Data for Method Comparisons

Parameter	Test 1	Test 2
A_W (m^2)	32.200	30.122
v_R (km/hr)	45 [132]	45 [312]
v_{CI} (km/hr)	10 [132]	10 [132]
v_{CO} (km/hr)	202.5	202.5
N_S	5	1
N_B	5	5

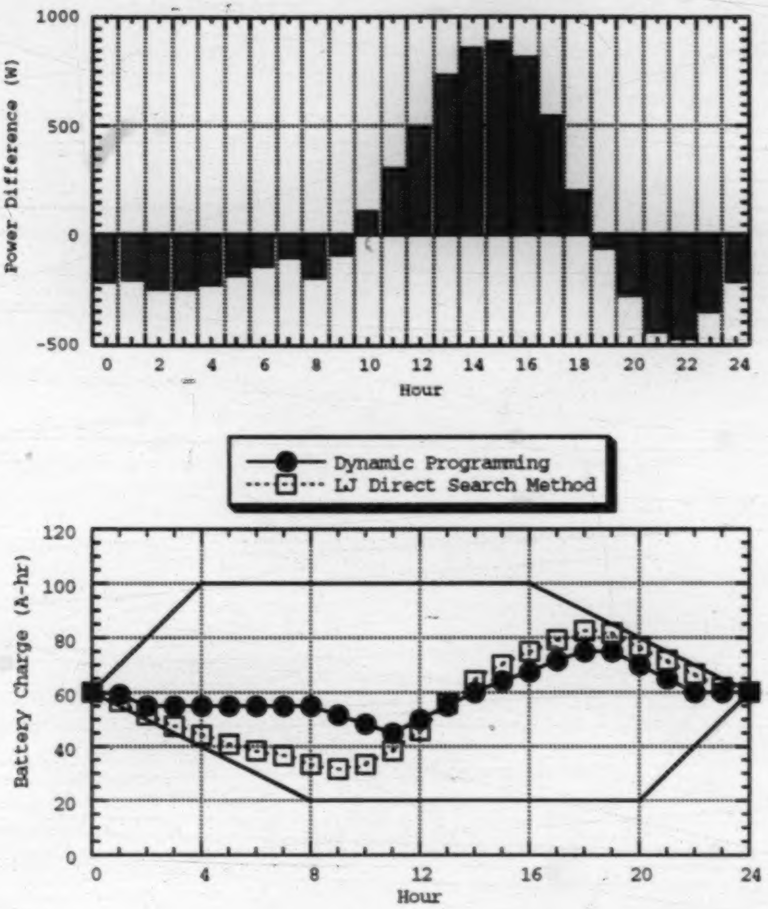


Figure 5.14-1. Comparison of Battery Optimization Methods (Case 1)

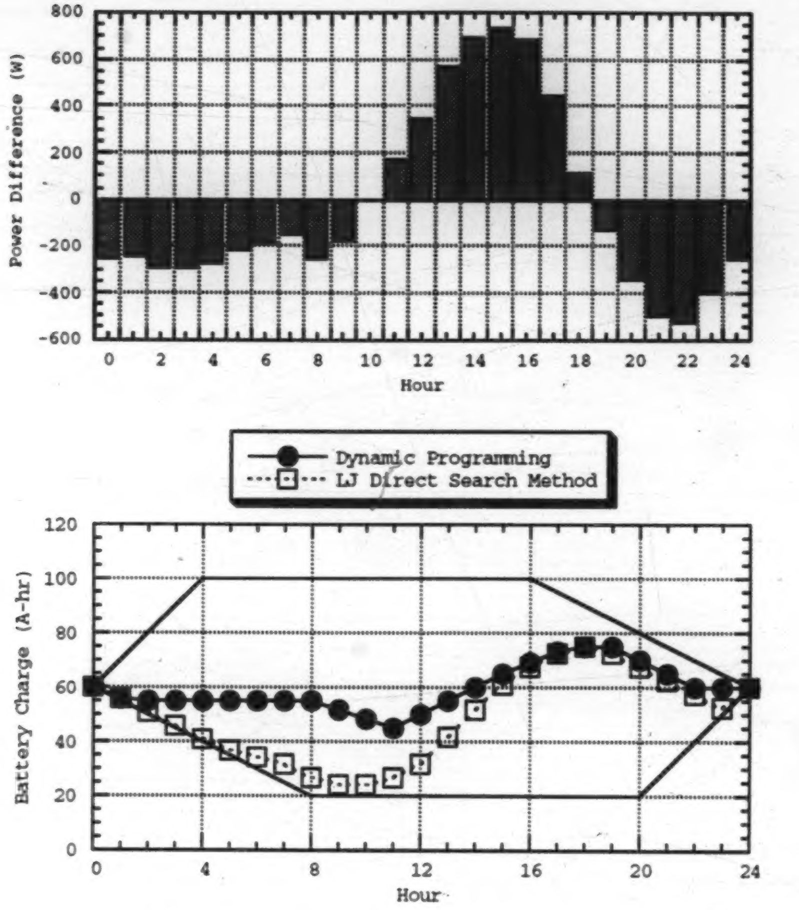


Figure 5.14-2. Comparison of Battery Optimization Methods (Case 2)

Dynamic programming optimizes the entire process across all stages, implying that the entire process must be known in advance. The method developed for this investigation, on the other hand, considers each individual stage and optimizes the path through the battery based on the associated constraints and limits. This approach would be more representative of an actual operational setting where, due to uncertainties in weather conditions and load demand, accurate forecasting of conditions for the next stage may not be possible.

In addition, the results obtained from the LJ direct search method show a greater depth of discharge, making more effective use of the available battery capacity. As a result, dependence upon the auxiliary generator would be reduced, lowering operating and maintenance costs.

5.15. Optimization Procedures

5.15.1. General

Each renewable energy system at each site considered has its own load demand and weather conditions.

As a result, a number of factors must be considered prior to an optimization run, as these will determine how the optimization should be initiated as well as the constraints which must be satisfied. This is done in order to account for the actual physical and operational conditions to which the system is subjected.

5.15.2. Daytime Operation

From 5.6.3.2., the system is to be designed so that during a certain period during the day, the combined output from the renewable energy sources during a given hour should meet or exceed the load demand. This can best be determined by examining the output power of the renewable energy sources during the day, from which suitable times can be selected.

5.15.3. Wind Turbine Generator

From 5.2.3.4, the operation of a WTG is dependent upon the cut-in, rated, and cut-out wind velocities. Since these values can vary between WTG models, the selection of which type to use can be made after considering the distribution of the wind velocities. The WTG which makes better use of the available wind speeds will be selected for the optimization.

5.15.4. Load

The magnitude of the load for which the system is to be optimized must be determined. This requires an analysis of the load demand with emphasis upon magnitude and frequency of occurrence.

A possible starting point for this analysis would be a load demand magnitude 20% above the historical peak values, allowing for forced outages of installed generation capacity [74]. This would be in keeping with practices in the power utility industry. Depending upon the load pattern, this magnitude could be successively reduced and the system optimized for the new values.

5.16. Interpretation and Application of Optimization Results

One practical application of this optimization method is as a design tool, providing a basis for determining a suitable configuration for a client. Of interest to a designer, then, is the practical applicability of the results of an optimization run.

This practicality can be determined by such factors as:

- seasonal effects on both available energy and load demand,
- maximum load demand to be met,
- the selection of constraints appropriate to the weather conditions and load demand at the client's site,
- the selection of components with operating characteristics which make best use of the energy available from the wind and sunlight,
- the selection of a suitable starting point for the optimization,
- the influence of upper and lower limits for specific constraints, and
- the determination of whether physical and/or operational constraints are more important in optimizing a given component than the component cost.

Much of this can be determined by varying some of the parameters in question and identifying any significant aspects from the results. In addition, utilizing a set of results from an optimization run in an operational simulation of the system can indicate whether those results would be suitable for development into an actual design.

To assist in the interpretation of the results, however, it is important to understand the behaviour of the load as far as possible, in, for example, the context of certain weather conditions. Such information could explain the occurrence of certain load values. In addition, this information could indicate what the load demand might be for, if it has not been specifically identified. This would assist in the design of the renewable energy system.

5.17. Edmonton Load 1

5.17.1. Symbols

A_W = wind turbine generator rotor area (m^2)
$A_{W_{MAX}}$ = maximum wind turbine generator rotor area (m^2)
$A_{W_{MIN}}$ = minimum wind turbine generator rotor area (m^2)
c_B = battery cost (\$/A-hr/battery)
c_F = fuel cost (\$/L)
c_S = photovoltaic module cost (\$/module)
c_W = wind turbine cost (\$/m^2)
f = auxiliary generator fuel consumption rate (L/day)
N_B = number of batteries
$N_{B_{MAX}}$ = maximum number of batteries
$N_{B_{MIN}}$ = minimum number of batteries
N_S = number of photovoltaic modules
$N_{S_{MAX}}$ = maximum number of photovoltaic modules
$N_{S_{MIN}}$ = minimum number of photovoltaic modules
$P_G^\bullet$ = required auxiliary generator capacity (W)
$P_{G_{MAX}}$ = maximum auxiliary generator capacity (W)
$P_{G_{MIN}}$ = minimum auxiliary generator capacity (W)
P_I = inverter capacity (W)
P_R = rectifier capacity (W)

5.17.2. Load Description

As mentioned in 5.2.6.2., data for several farm loads in the vicinity of Edmonton were obtained from Atco Electric. One of these loads was used for developing and testing the optimization algorithm. Although the exact nature was not known, an examination of the load demand data, together with corresponding weather data, indicated what it might represent.

A histogram for the entire load data together is shown in Figure 5.2-10. The data range from zero to just over 4500 W and do not display any major long-term seasonal characteristics. The variations in the average hourly values are shown in Figure 5.5-2.

Much of the behaviour of the load can be understood by comparing actual hourly load values during a given time period with corresponding weather data. In this case, the weather data covered the calendar years 1978 - 1997, while the load data was for the calendar 1993 - 1997.

For example, many of the load demands above 3500 W occur in the context of lower temperatures and/or higher wind speeds during winter, which can be seen in Table 5.17-1. These higher values are possibly due to the use of appliances such as electric space heaters. References such as [157] provide further information regarding power requirements for various appliances and farm equipment.

The magnitudes of these load demands plus the correlation between their occurrence and certain weather conditions indicate that a load such as this one might represent that for a small farm residence.

5.17.3. Renewable Energy Sources

5.17.3.1. Photovoltaic Module

The mean hourly output power for the PV module is shown in Figure 5.17-1. By inspection, it generates significant amounts of power between 1000 and 1500 hours local time. It is during these times that the combined output power from both renewable energy sources should meet or exceed the load demand as described in 5.6.4.1.

5.17.3.2. Wind Turbine Generator

The histogram for all the wind speeds is shown in Figure 5.17-2. Of note is that the speed with the highest relative frequency is 6 km/hr, with over 50% of the wind speeds less than or equal to 10 km/hr. In order for a WTG to effectively produce power with such a distribution of wind speeds, a low cut-in speed would be required. Of the two models considered for this investigation, the small-capacity WTG described in 5.12. and Table 5.12-1 would be better suited for the load at this site.

5.17.4. Initial Optimization Results

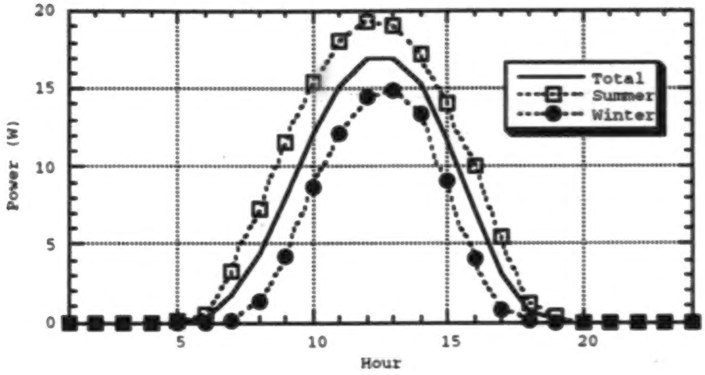
5.17.4.1. General

As an initial survey, the data sets combining the summer and winter values were examined. This survey consisted of a series of different cases in which the following were considered:

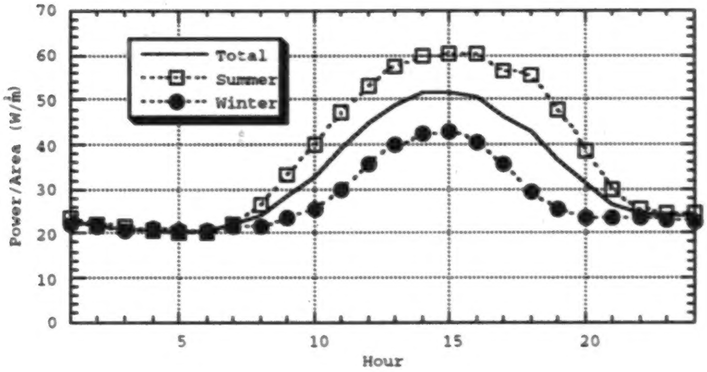
- the maximum load demand,
- the prices for the renewable energy sources and fuel,
- the minimum number of PV modules, and

Table 5.17-1. Conditions for Edmonton Load 1 Demands Above 3500 W

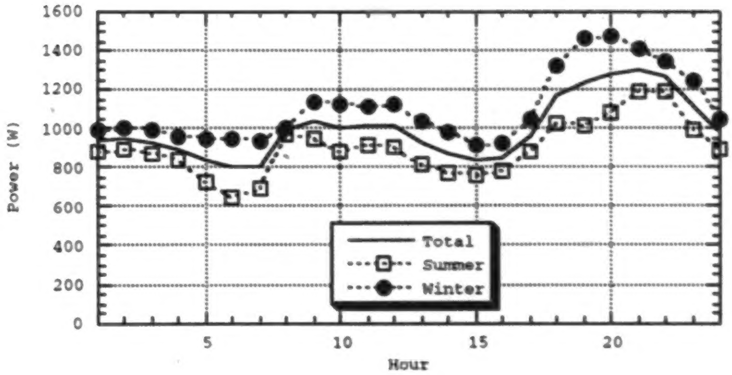
Date	Hour	Temp. (°C)	Wind (km/hr)	Rad. (W/m^2)	Load (W)
1993-01-01	11	-27.00	9.00	290.74	3812
1993-01-01	12	-25.90	9.00	383.67	4262
1993-01-01	13	-25.10	9.00	329.43	4234
1993-01-01	14	-24.40	11.00	287.59	3557
1993-01-09	20	-17.90	24.00	0.00	3546
1993-01-11	15	-21.50	6.00	87.46	3586
1993-02-25	22	-6.30	13.00	0.00	3733
1993-03-11	10	-7.20	13.00	730.65	4561
1993-03-11	11	-5.90	17.00	783.07	4108
1993-03-12	10	-9.70	17.00	676.99	3640
1993-03-16	11	-16.60	9.00	992.83	3744
1993-10-16	20	6.70	4.00	0.00	3780
1993-12-02	18	0.70	11.00	0.00	4000
1994-02-24	20	-23.30	6.00	0.00	4097
1994-11-03	20	-2.30	19.00	0.00	4439
1994-11-03	21	-3.10	20.00	0.00	4151
1994-11-03	22	-3.10	15.00	0.00	4111
1994-11-03	23	-2.80	20.00	0.00	3665
1994-11-03	24	-2.50	20.00	0.00	3726
1994-11-04	1	-2.80	19.00	0.00	3733
1994-11-04	2	-2.20	15.00	0.00	3726
1994-11-04	3	-1.80	9.00	0.00	3726
1994-11-04	4	-2.00	9.00	0.00	3654
1994-11-04	5	-2.20	0.00	0.00	3665
1994-12-24	17	-6.10	4.00	0.07	4097
1995-01-08	15	-17.40	15.00	55.83	3658
1996-01-24	21	-24.60	7.00	0.00	3784
1996-01-24	22	-24.60	7.00	0.00	4054
1996-03-08	2	-19.50	22.00	0.00	3593



Mean PV Module Output Power



Mean WTG Output Power/Area



Mean Load Demand

Figure 5.17-1. Edmonton Load 1 Mean Photovoltaic Module Output Power, Wind Turbine Generator Output Power/Area, and Load Demand

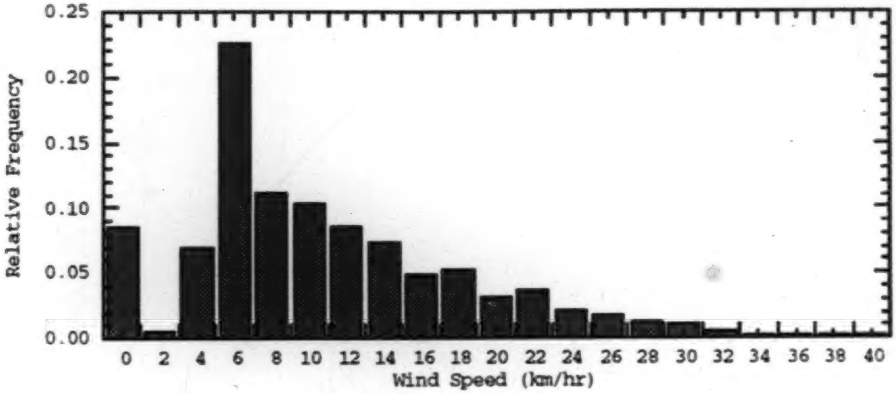


Figure 5.17-2. Wind Speed Histogram for Edmonton (Total Data Set)

- the minimum number of batteries.

One set of cases had the aforementioned prices at typical market values, while another set of cases considered the renewable energy source to 25% of the original values and fuel costs reduced by a third. The lower renewable energy source prices were meant to represent such things as:

- reductions in costs due to improved manufacturing techniques and/or energy technology,
- financial assistance through government subsidies or tax incentives, and
- large dealer discounts.

The value of 25% was chosen as a typical representation of an extreme reduction in price. The reduction in the fuel price was meant to represent lower costs due to, for example, tax exemptions, such as the one referred to in 5.9.8.

This survey was repeated for the data set in which seasonal effects were taken into account with the summer and winter data separated.

5.17.4.2. Constraints and Limits

The initial survey was conducted using as the constraints and limits given in Table 5.17-2.

The upper limit on the WTG area was set to 100 m^2, as during earlier testing of the algorithm, results indicated that a value of the same order of magnitude would be required. By setting high upper limits on the number of PV modules and batteries, the optimization algorithm could produce results largely dependent upon these components. Lower limits were set for them to determine what effect imposing them would have on the results produced by the algorithm.

Also, the magnitude of the auxiliary generator allows most of the load demand to be met should there be no power available from the renewable energy sources.

5.17.4.3. Starting Point

The starting points for this survey are given in Table 5.17-3. A variety of starting points were used during the earlier part of the survey in order to study the behaviour of the optimization algorithm.

Table 5.17-2. Constraints and Limits for Edmonton Load 1 Initial Survey

Parameter	Value
$A_{W_{MAX}}$	100 m^2
$A_{W_{MIN}}$	0 m^2
$N_{S_{MAX}}$	200
$N_{S_{MIN}}$	0, 5
$N_{B_{MAX}}$	200
$N_{B_{MIN}}$	0, 5
$P_{G_{MAX}}$	2500 W
$P_{G_{MIN}}$	250 W

Table 5.17-3. Starting Points for Edmonton Load 1 Initial Survey

	Full Prices			Reduced Prices		
Load (W)	A_W (m^2)	N_S	N_B	A_W (m^2)	N_S	N_B
	$N_{S_{MIN}} = 0/N_{B_{MIN}} = 0$ (Total Data Set)					
100%	99	0	0	99	5	5
4000	95	10	5	99	10	5
3500	99	10	5	99	10	5
3000	99	10	5	99	10	5
2500	99	10	5	99	10	5
Mean	99	10	5	99	10	5
	$N_{S_{MIN}} = 0/N_{B_{MIN}} = 5$ (Total Data Set)					
100%	99	0	6	99	5	5
4000	95	10	5	99	10	5
3500	99	10	5	99	10	5
3000	99	10	5	99	10	5
2500	99	10	5	99	10	5
Mean	99	10	5	99	10	5
	$N_{S_{MIN}} = 5/N_{B_{MIN}} = 0$ (Total Data Set)					
100%	99	10	0	99	10	5
4000	95	10	5	99	10	5
3500	99	10	5	99	10	5
3000	99	10	5	99	10	5
2500	99	10	5	99	10	5
Mean	99	10	5	99	10	5
	$N_{S_{MIN}} = 5/N_{B_{MIN}} = 5$ (Total Data Set)					
100%	99	5	0	99	5	5
4000	95	10	5	99	10	5
3500	99	10	5	99	10	5
3000	99	10	5	99	10	5
2500	99	10	5	99	10	5
Mean	99	10	5	99	10	5

Table 5.17-3. Starting Points for Edmonton Load 1 Initial Survey (Cont'd)

	Full Prices			Reduced Prices		
Load (W)	A_W (m^2)	N_S	N_B	A_W (m^2)	N_S	N_B
$N_{S_{MIN}} = 0/N_{B_{MIN}} = 0$ (Seasonal Data Set)						
100%	99	10	0	99	10	0
4000	99	10	0	99	10	0
3500	99	10	0	99	10	0
3000	99	10	0	99	10	0
2500	99	10	5	99	10	5
Mean	99	10	5	99	10	5
$N_{S_{MIN}} = 0/N_{B_{MIN}} = 5$ (Seasonal Data Set)						
2500	99	10	5	99	10	5
Mean	99	10	5	99	10	5
$N_{S_{MIN}} = 5/N_{B_{MIN}} = 0$ (Seasonal Data Set)						
100%	99	10	0	99	10	0
4000	99	10	0	99	10	0
3500	99	10	0	99	10	0
3000	99	10	0	99	10	0
2500	99	10	5	99	10	5
Mean	99	10	5	99	10	5
$N_{S_{MIN}} = 5/N_{B_{MIN}} = 5$ (Seasonal Data Set)						
2500	99	10	5	99	10	5
Mean	99	10	5	99	10	5

5.17.4.4. Loads

This survey used a range of maximum loads for which the systems were to be optimized. The maximum load for each hour was progressively reduced from 100% of the historical values down to 2500 W in 500 W increments. This reduction would be similar to load-shedding when a portion of the load is disconnected should there be insufficient power from all available sources.

For comparison, cases using the mean load for each hour were also examined.

5.17.4.5. System Configurations

In addition to changes in costs, the cases examined in the initial survey considered seasonal effects and the influence of small lower limits on the number of PV modules and batteries. The loads on which the respective optimizations were based are shown in Figure 5.17-3, with the results are presented in Tables 5.17-4 - 5.17-11. Several runs were required for these results, with values from the previous runs as the new starting points, as given in [132].

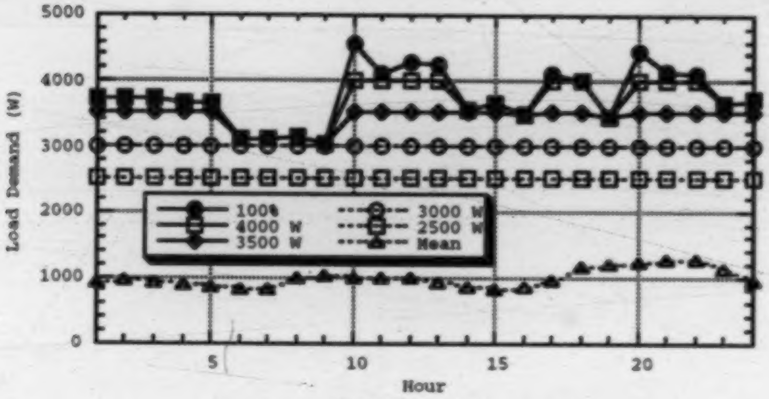
Many of the systems examined required large WTG areas. This can be explained by the mean available WTG power per unit area being greater than zero for each hour and season, providing, in the long term, a constant supply of power.

Tables 5.17-4 and 5.17-8 show that the optimization algorithm tends, when full market prices are in effect, to produce systems without PV modules and batteries. However, in Table 5.17-4, this changes when the applicable prices are reduced, showing that capital and fuel costs have a significant influence on the design of a system.

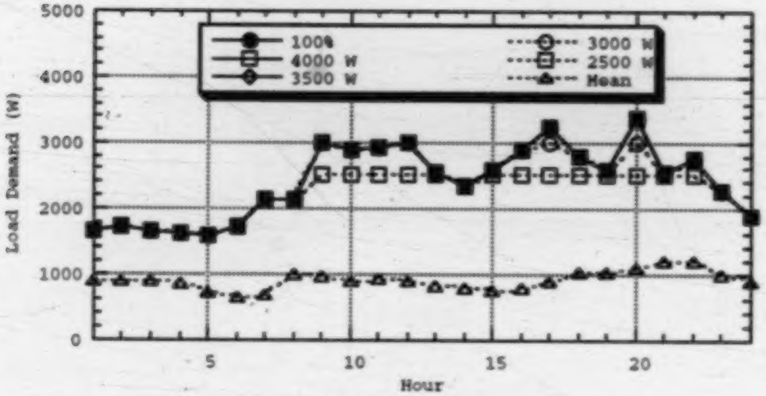
In Tables 5.17-4 - 5.17-7, the case of 100% maximum load at reduced costs has a large WTG area with 28 PV modules and 5 batteries, with the number of PV modules increasing from the starting point. In several other cases, the number of batteries was increased from the starting point, though Tables 5.17-4 - 5.17-7 show that this occurs only when prices are reduced.

When seasonal effects are taken into account and no lower limits on the number of PV modules and batteries are imposed (Table 5.17-8), few of the systems examined required PV modules or batteries. This can be explained by power from the wind being available every hour.

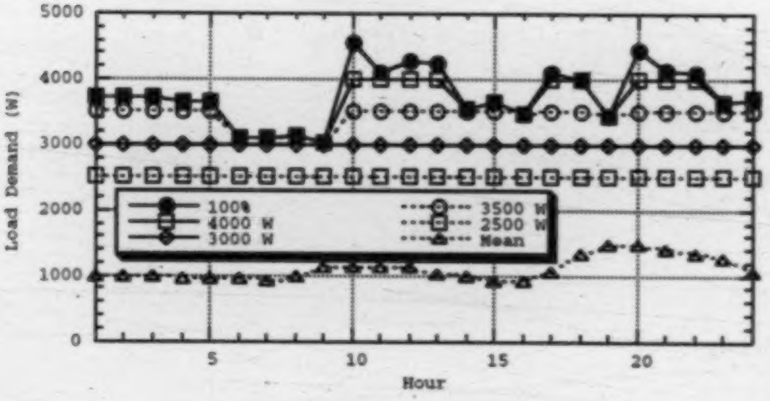
In Table 5.17-8, when full prices are in effect, the case for



Total



Summer



Winter

Figure 5.17-3. Maximum Demand for Edmonton Load 1

Table 5.17-4. Initial Optimization Results for Edmonton Load 1 ($N_{S_{MIN}}$ = 0, $N_{B_{MIN}}$ = 0, Total Data Set)

Case							Results							
Load (W)	$N_{S_{MIN}}$	$N_{B_{MIN}}$	c_W (\$/m^2)	c_S (\$/mod.)	c_B (\$/A-hr/btty.)	c_F (\$/L)	A_W (m^2)	N_S	N_B	P_G^* (W)	P_I (W)	P_B (W)	f (L/day)	Cost (\$/yr)
100%	0	0	800	500	2.50	0.45	70.63	1	0	2500	250	0	11.21	13066
4000	0	0	800	500	2.50	0.45	70.63	1	0	2500	250	0	10.96	13000
3500	0	0	800	500	2.50	0.45	49.86	0	0	2500	0	0	13.19	11558
3000	0	0	800	500	2.50	0.45	24.93	0	0	2500	0	0	14.38	9241
2500	0	0	800	500	2.50	0.45	1.04	0	0	2500	0	0	15.25	6948
Mean	0	0	800	500	2.50	0.45	0.00	0	0	1500	0	0	6.37	3434
100%	0	0	200	125	0.625	0.30	99.72	28	5	1500	500	1000	3.79	6144
4000	0	0	200	125	0.625	0.30	99.72	0	4	1500	500	500	4.19	5885
3500	0	0	200	125	0.625	0.30	99.72	0	8	1500	1000	1000	3.32	5784
3000	0	0	200	125	0.625	0.30	92.44	0	16	250	1000	2000	0.23	4277
2500	0	0	200	125	0.625	0.30	77.90	0	15	250	1000	1500	0.09	3616
Mean	0	0	200	125	0.625	0.30	32.20	0	5	250	500	1000	0.13	1582

Table 5.17-5. Initial Optimization Results for Edmonton Load 1 ($N_{S_{MIN}} = 0$, $N_{B_{MIN}} = 5$, Total Data Set)

Case							Results							
Load (W)	$N_{S_{MIN}}$	$N_{B_{MIN}}$	c_W (\$/m^2)	c_S (\$/mod.)	c_B (\$/A-hr/btty.)	c_F (\$/L)	A_W (m^2)	N_S	N_B	P_G^* (W)	P_I (W)	P_R (W)	f (L/day)	Cost (\$/yr)
100%	0	5	800	500	2.50	0.45	99.72	0	5	2000	500	1000	5.68	14434
4000	0	5	800	500	2.50	0.45	99.72	0	5	1500	500	1000	4.14	13623
3500	0	5	800	500	2.50	0.45	96.60	0	5	1500	500	1000	3.76	13200
3000	0	5	800	500	2.50	0.45	82.06	0	5	1500	500	1000	3.72	11658
2500	0	5	800	500	2.50	0.45	71.67	0	5	1000	500	1000	2.15	9621
Mean	0	5	800	500	2.50	0.45	30.12	0	5	1000	500	1000	0.94	4601
100%	0	5	200	125	0.625	0.30	99.72	28	5	1500	500	1000	3.79	6144
4000	0	5	200	125	0.625	0.30	100.75	0	5	1500	500	1000	4.10	5991
3500	0	5	200	125	0.625	0.30	99.72	0	8	1500	1000	1000	3.32	5784
3000	0	5	200	125	0.625	0.30	92.44	0	16	250	1000	2000	0.23	4277
2500	0	5	200	125	0.625	0.30	76.86	0	13	250	1000	1500	0.29	3613
Mean	0	5	200	125	0.625	0.30	32.20	0	5	250	500	1000	0.13	1582

Table 5.17-6. Initial Optimization Results for Edmonton Load 1 ($N_{S_{MIN}}$ = 5, $N_{B_{MIN}}$ = 0, Total Data Set)

Case							Results							
Load (W)	$N_{S_{MIN}}$	$N_{B_{MIN}}$	c_W ($/m^2)	c_S ($/mod.)	c_B ($/A-hr/btty.)	c_F ($/L)	A_W (m^2)	N_S	N_B	P_G^* (W)	P_I (W)	P_R (W)	f (L/day)	Cost ($/yr)
100%	5	0	800	500	2.50	0.45	70.63	5	0	2500	250	0	11.18	13288
4000	5	0	800	500	2.50	0.45	70.63	5	0	2500	250	0	10.92	13221
3500	5	0	800	500	2.50	0.45	49.86	5	0	2500	250	0	13.13	11859
3000	5	0	800	500	2.50	0.45	25.97	5	0	2500	250	0	14.21	9624
2500	5	0	800	500	2.50	0.45	1.04	5	0	2500	250	0	15.18	7249
Mean	5	0	800	500	2.50	0.45	0.00	5	0	1500	250	0	6.33	3741
100%	5	0	200	125	0.625	0.30	99.72	28	5	1500	500	1000	3.79	6144
4000	5	0	200	125	0.625	0.30	98.68	5	4	1500	500	500	4.20	5924
3500	5	0	200	125	0.625	0.30	99.72	5	8	1500	1000	1000	3.30	5854
3000	5	0	200	125	0.625	0.30	92.44	5	17	250	1500	2000	0.16	4424
2500	5	0	200	125	0.625	0.30	76.86	5	14	250	1000	1500	0.16	3663
Mean	5	0	200	125	0.625	0.30	32.20	5	5	250	500	1000	0.13	1654

Table 5.17-7. Initial Optimization Results for Edmonton Load 1 ($N_{S_{MIN}}$ = 5, $N_{B_{MIN}}$ = 5, Total Data Set)

Case							Results							
Load (W)	$N_{S_{MIN}}$	$N_{B_{MIN}}$	c_W (\$/m^2)	c_S (\$/mod.)	c_B (\$/A-hr/btty.)	c_F (\$/L)	A_W (m^2)	N_S	N_B	P_G^* (W)	P_I (W)	P_R (W)	f (L/day)	Cost (\$/yr)
100%	5	5	800	500	2.50	0.45	99.72	5	5	2000	500	1000	5.65	14717
4000	5	5	800	500	2.50	0.45	99.72	5	5	1500	500	1000	4.12	13907
3500	5	5	800	500	2.50	0.45	95.56	5	5	1500	500	1000	3.78	13386
3000	5	5	800	500	2.50	0.45	83.10	5	5	1500	500	1000	3.68	12044
2500	5	5	800	500	2.50	0.45	71.67	5	5	1000	500	1000	2.15	9908
Mean	5	5	800	500	2.50	0.45	31.16	5	5	500	500	1000	0.33	4632
100%	5	5	200	125	0.625	0.30	99.72	28	5	1500	500	1000	3.79	6144
4000	5	5	200	125	0.625	0.30	99.72	10	5	1500	500	1000	3.92	6071
3500	5	5	200	125	0.625	0.30	99.72	5	8	1500	1000	1000	3.30	5854
3000	5	5	200	125	0.625	0.30	92.44	5	17	250	1500	2000	0.16	4424
2500	5	5	200	125	0.625	0.30	76.86	5	14	250	1000	1500	0.16	3663
Mean	5	5	200	125	0.625	0.30	32.20	5	5	250	500	1000	0.13	1654

Table 5.17-8. Initial Optimization Results for Edmonton Load 1 ($N_{S_{MIN}}$ = 0, $N_{B_{MIN}}$ = 0, Seasonal Data Set)

Case							Results							
Load (W)	$N_{S_{MIN}}$	$N_{B_{MIN}}$	c_W (\$/m^2)	c_S (\$/mod.)	c_B (\$/A-hr/btty.)	c_F (\$/L)	A_W (m^2)	N_S	N_B	P_G^* (W)	P_I (W)	P_R (W)	f (L/day)	Cost (\$/yr)
100%	0	0	800	500	2.50	0.45	91.41	0	0	2500	0	0	5.73	12564
4000	0	0	800	500	2.50	0.45	78.94	0	0	2500	0	0	7.46	12049
3500	0	0	800	500	2.50	0.45	50.90	0	0	2500	0	0	10.78	10733
3000	0	0	800	500	2.50	0.45	24.93	0	0	2500	0	0	13.39	8971
2500	0	0	800	500	2.50	0.45	0.00	0	0	2500	0	0	14.90	6749
Mean	0	0	800	500	2.50	0.45	42.59	1	2	500	250	250	0.23	5017
100%	0	0	200	125	0.625	0.30	96.60	0	0	2500	0	0	5.21	5816
4000	0	0	200	125	0.625	0.30	93.48	0	0	2000	0	0	4.29	5313
3500	0	0	200	125	0.625	0.30	98.68	0	0	1500	0	0	2.52	4811
3000	0	0	200	125	0.625	0.30	96.60	0	0	1500	0	0	2.28	4420
2500	0	0	200	125	0.625	0.30	85.17	1	1	1000	250	250	1.41	3784
Mean	0	0	200	125	0.625	0.30	42.59	1	2	500	250	250	0.23	1826

Table 5.17-9. Initial Optimization Results for Edmonton Load 1 ($N_{S_{MIN}}$ = 0, $N_{B_{MIN}}$ = 5, Seasonal Data Set)

Case							Results							
Load (W)	$N_{S_{MIN}}$	$N_{B_{MIN}}$	c_W (\$/m^2)	c_S (\$/mod.)	c_B (\$/A-hr/btty.)	c_F (\$/L)	A_W (m^2)	N_S	N_B	P_G^* (W)	P_I (W)	P_R (W)	f (L/day)	Cost (\$/yr)
2500	0	5	800	500	2.50	0.45	89.33	0	5	1000	500	1000	1.03	10963
Mean	0	5	800	500	2.50	0.45	40.51	0	5	1000	500	1000	0.40	5326
2500	0	5	200	125	0.625	0.30	96.60	0	5	500	500	1000	0.35	3958
Mean	0	5	200	125	0.625	0.30	43.62	0	5	250	500	500	0.08	1903

Table 5.17-10. Initial Optimization Results for Edmonton Load 1 ($N_{S_{MIN}}$ = 5, $N_{B_{MIN}}$ = 0, Seasonal Data Set)

Case							Results							
Load (W)	$N_{S_{MIN}}$	$N_{B_{MIN}}$	c_W (\$/m^2)	c_S (\$/mod.)	c_B (\$/A-hr/btty.)	c_F (\$/L)	A_W (m^2)	N_S	N_B	P_G^* (W)	P_I (W)	P_R (W)	f (L/day)	Cost (\$/yr)
100%	5	0	800	500	2.50	0.45	89.33	5	0	2500	250	0	5.79	12714
4000	5	0	800	500	2.50	0.45	89.33	5	0	2000	250	0	4.53	12126
3500	5	0	800	500	2.50	0.45	50.90	5	0	2500	250	0	10.73	11039
3000	5	0	800	500	2.50	0.45	24.93	5	0	2500	250	0	13.33	9271
2500	5	0	800	500	2.50	0.45	0.00	5	0	2500	250	0	14.83	7050
Mean	5	0	800	500	2.50	0.45	41.55	5	3	500	250	500	0.20	5282
100%	5	0	200	125	0.625	0.30	89.33	5	0	2000	250	0	4.53	5374
4000	5	0	200	125	0.625	0.30	89.33	5	0	2000	250	0	4.53	5374
3500	5	0	200	125	0.625	0.30	98.68	5	0	1500	250	0	2.52	4911
3000	5	0	200	125	0.625	0.30	96.60	5	0	1500	250	0	2.27	4520
2500	5	0	200	125	0.625	0.30	85.17	5	1	1000	250	250	1.40	3842
Mean	5	0	200	125	0.625	0.30	42.59	5	2	500	250	250	0.23	1884

Table 5.17-11. Initial Optimization Results for Edmonton Load 1 ($N_{S_{MIN}}$ = 5, $N_{B_{MIN}}$ = 5, Seasonal Data Set)

Case							Results							
Load (W)	$N_{S_{MIN}}$	$N_{B_{MIN}}$	C_W (\$/m^2)	C_S (\$/mod.)	C_B (\$/A-hr/btty.)	C_F (\$/L)	A_W (m^2)	N_S	N_B	P_G^* (W)	P_I (W)	P_R (W)	f (L/day)	Cost (\$/yr)
2500	5	5	800	500	2.50	0.45	89.33	5	5	1000	500	1000	1.03	11240
Mean	5	5	800	500	2.50	0.45	40.51	5	5	1000	500	1000	0.40	5596
2500	5	5	200	125	0.625	0.30	96.60	5	5	250	500	1000	0.18	3995
Mean	5	5	200	125	0.625	0.30	42.59	5	7	250	500	1000	0.06	2011

a 2500 W maximum load required only an auxiliary generator, indicating that the use of renewable energy sources for this load would not be economical. This changes when the prices are reduced for that load when renewable energy sources are required.

Of note is the case using 100% of the load demand with the prices reduced (Tables 5.17-4 - 5.17-7). This system requires a large WTG area, 28 PV modules, and 5 batteries, with an explanation for situations such as this available in Figure 5.17-3. The nominal WTG area was limited to an upper limit of 100 m^2. At night, the power available from the WTG's would be sufficient to meet the load demand when supplemented by batteries and, if necessary, the auxiliary generator. During the day, however, the load increases significantly and the combined output power of the WTG's and batteries would be insufficient to meet it. Additional power would then be required by the PV modules.

From Figure 5-17.4-1, the load becomes progressively uniform as the maximum load demand provided is reduced with the optimized systems for these loads are based primarily on WTG's. Since the loads for these systems remain constant throughout the day and the WTG's are optimized for that load, the need for extra power from PV modules diminishes and the number of batteries required reduced.

Component cost also has an effect upon most of the systems obtained. Consider, for example, the case of 100% load and no minimum limit on the number of PV modules and batteries, using the both summer and winter values combined for the input (Table 5.17-4). No batteries were required for the optimum configuration when full market prices were in effect. By comparison, when those prices were reduced, the system requires much more WTG area, 28 PV modules, and 5 batteries. At the same time, the required auxiliary generator capacity was reduced by 40% in the latter case.

One explanation for this is as follows. The reduction in costs would allow the purchase of more renewable energy capacity, hence the greater WTG area and the presence of PV modules. This additional capacity would make it feasible to use batteries as excess energy from the WTG and PV module (after meeting the load demand) will likely be available for charging. The batteries can then be used as a supplementary source when the combined power from the WTG and PV modules is insufficient to meet the load demand, reducing the required auxiliary generator capacity.

Many of the lower-cost systems in Tables 5.17-4 and 5.17-8 require small numbers of either PV modules or batteries. To check if this is influenced by forcing the algorithm to include at least a small number of PV modules and/or batteries, cases for which the lower limits were specifically set to combinations of either zero or 5 PV modules and batteries were examined. The results are presented in Tables 5.17-5 - 5.17-7 and 5.17-9 - 5.17-11.

Consider, for example, the systems in Table 5.17-5 for which full market prices are in effect. These systems require both more WTG area and smaller auxiliary generator capacities than for the corresponding cases in Table 5.17-4. The increased WTG capacity would be necessary for charging batteries while meeting the load demand.

For those cases in which a minimum of 5 PV modules was required and the combined data sets are used (Tables 5.17-6 and 5.17-7), the optimization algorithm produces systems with the imposed minimum. This indicates that, for the conditions under which the optimization algorithm is run, the systems do not, by themselves, require PV modules, based on the starting point used for the survey.

When seasonal effects are considered, only the cases for a 2500 W maximum load and mean load allow for batteries. Additional testing for cases with larger loads indicated that a total WTG area of more than 105 m^2 would be required to support batteries for seasonal cases. This can be attributed to the magnitude of the maximum hourly loads, which occur during the winter. During this season, the mean output powers available from the renewable sources are almost always lower than during the summer. Any batteries which would be present in these systems would not be properly recharged under the constraints imposed upon the process duty cycle. Often, they would be sufficiently discharged to a point that when an attempt to recharge them is made, particularly late at night, a constraint is violated.

The information in Tables 5.17-4 - 5.17-11 shows that the upper limit on the WTG and lower limits on the number of PV modules and batteries are major influences on the design of a system. This can be seen since in nearly each case, the optimization algorithm requires as much WTG area as possible, while in most of the cases examined, the numbers of PV modules and batteries tend to decrease from the initial starting point.

In addition, the costs shown in these tables indicate that for maximum loads of at least 3500 W, the annual costs are of approximately the same magnitude (see, for example, 5.17-5). This is also reflected in a similarity in the results produced by the optimization algorithm. On the other hand, the annual costs drop by about a factor of 2 between the loads are between 2500 W and the mean.

5.17.5. Initial Simulation Results

5.17.5.1. Simulation Description

Though the objective function for the optimization is the annual capital, operating and maintenance cost of a hybrid energy system, the technical suitability and practicality of a design is also important in its selection and possible application. This can be examined by testing it either with actual hardware or by means of a simulation.

For this investigation, an approximate simulation was formulated using the battery model derived for the optimization algorithm as a basis. Actual hourly weather data was read and the applicable WTG power per unit area and PV module power were calculated for the corresponding times.

Similarly, the hourly load demand data was also read. Since this data covered only 5 years, while the weather data covered 20, the load demand data was read in sequence an additional 3 times to give the same number of points for each. This allows a larger number of days to be examined, but those cases when the weather data and load data are from different times (say, 1978 weather data being used with 1993 load data), the results may be misleading.

The purpose of this simulation is to check the performance of a given configuration and to determine if it may be suitable for a design. It can be used to determine potential problems in the configuration which the optimization algorithm may be unable to detect as well as pinpointing any shortcomings in the algorithm itself.

5.17.5.2. Configuration Testing

For a given design to be considered suitable, it must make effective use of the energy available by not only meeting the load demand as often as possible but also minimizing any power surplus or deficiency. In addition, the system is to be designed so that the renewable energy sources are to be the primary sources of power for meeting the load demand. For this purpose, some storage capacity would be desirable should insufficient wind or sunlight be available.

To evaluate a system, data from a set of individual days arbitrarily selected from the set were used. Systems which are heavily dependent on one or the other renewable source may not be desirable. During prolonged periods of unfavourable weather conditions, this source may not produce sufficient amounts of power. Any shortfall would have to be provided by the auxiliary generator, adding to operating and maintenance expenses. In addition, should conditions be suitable and the renewable energy source in question operate near or at full capacity, large of amounts of power in excess of that required to meet the load demand could result. This excess power could be used for battery charging, but since charge current and operating voltage constraints are in effect, much of it could go unused.

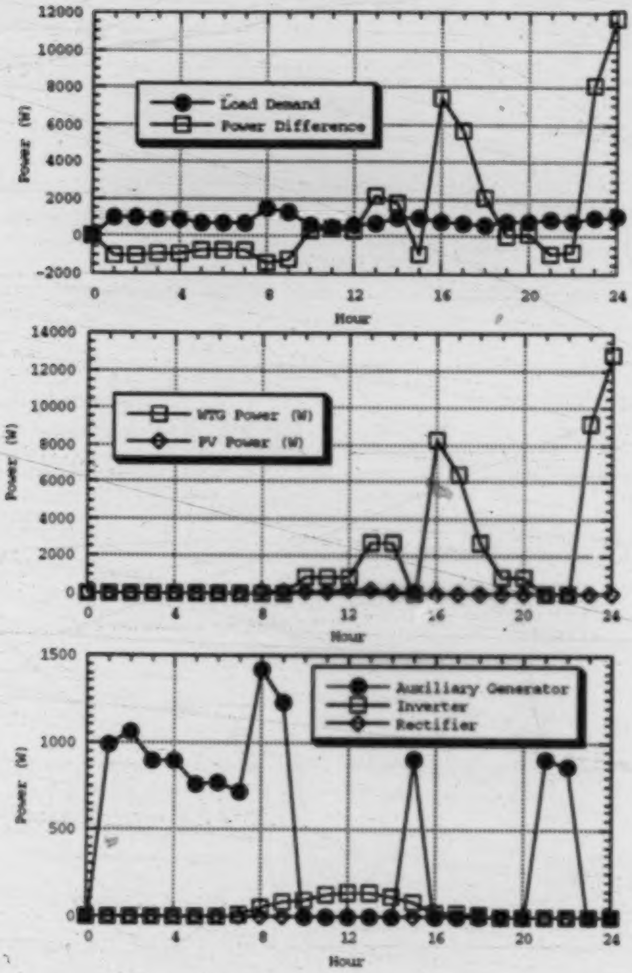
One possibility for utilizing this excess power is by operating an auxiliary load. This load would not be part of the main load and would be operated only if extra power was available. One example would be an air conditioner during the summer, when temperatures are higher, but also more sunlight (and, therefore, more PV module power) would be available. The use of an auxiliary load was examined in publications such as [157].

As an example, Figure 5.17-4 shows the results for one such system. The auxiliary generator operates for 12 hours in total, but only when no power from the WTG and/or PV modules is available. Of note, though, is the output power from the WTG's during the late afternoon and late at night. During both periods, there is a large amount of excess power available, particularly at midnight, when the WTG's produce nearly 12 kW more power than the load requires.

By comparison, a system based on the lower costs and mean loads (Table 5.17-8) would not be suitable as the required auxiliary generator capacity is 500 W and the minimum load demand for that day is 576 W. In order for this system to successfully operate during this day, the auxiliary generator capacity would have to be about 2000 W. This is shown in Figure 5.17-5.

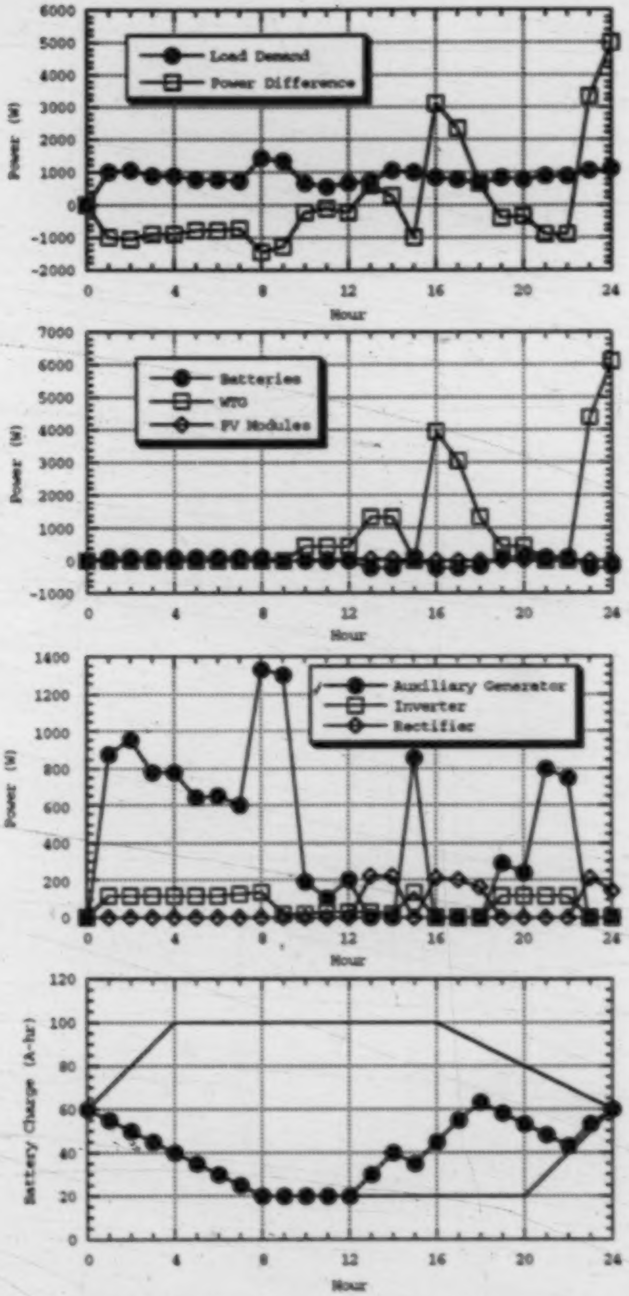
5.17.5.3. Systems Based on Mean Loads

Due to the irregularity of the available wind speeds, a system using a larger WTG area may not be suitable. From the WTG histogram (Figure 5.17-2), the WTG's will remain idle for large periods of time, as about 40% of the wind speeds are below the WTG's cut-in value. This represents a large capital investment for under-used equipment. A larger area will result in more power being produced when sufficient wind speeds are available, but this could also result in large amounts of excess power when they operate. Since the system is meant to be stand-alone, this excess power cannot be sold to a utility, which would otherwise provide a return on the capital investment.



A_w = 89.33 m^2 N_s = 5 N_b = 0
P_r^c = 2500 W P_i = 250 W P_b = 0

Figure 5.17-4. Run 1 for 1981, Day 98



A_a = 42.59 m^2 N_s = 1 N_p = 2

P_r^c = 2000 W P_i = 250 W P_a = 250 W

Figure 5.17-5. Run 2 for 1981, Day 98

Systems with smaller WTG areas would be preferable for several reasons. Although they will not produce as much power as those with larger areas for the same wind speed, they will still utilize any wind that becomes available. Smaller areas will also yield less excess power, though during those periods when the WTG's are the primary source, the probability of power shortfalls increases. In addition, the smaller capacity could also result in lower maintenance costs, in accordance with 5.9.6.2.

From this standpoint, it would be desirable to optimize the renewable energy system using data which would produce smaller WTG areas.

From Tables 5.17-4 - 5.17-11, systems based on mean loads had, on the whole, the smallest WTG areas as well as the lowest costs. Since the mean loads were the long-term values for the load demands, and the larger maximum values examined occur infrequently, the WTG's for these latter systems would be more cost-effective for the same weather conditions.

5.17.6. Revisions to Method

5.17.6.1. General

Most of the optimization cases examined in Tables 5.17-4 - 5.17-11 had the same starting point. The results for these cases required few, if any, PV modules and/or batteries. The starting point was selected as it provided feasible solutions in view of the load demands in effect as well as the constraints placed on the WTG area (see 5.4.1.3.). Revising the constraints and starting point may result in different systems being produced, possibly some with more PV modules and batteries.

For that purpose, a lower load was selected for further investigation. It was found that mean loads, which are the long-term magnitudes, allowed for higher optimization starting points. In addition, these loads also displayed both hourly and seasonal variations for all data sets, which most of the other loads examined did not always do (as shown in Figure 5.17-3), possibly affecting the results of the optimization.

Another reason that a higher starting point was investigated was to determine if a local minimum existed between it and the minima in the initial survey. This local minimum may include more PV modules and batteries than those found in the survey. If such a local minimum existed, the optimization results could provide the basis for an actual design.

5.17.6.2. Setup

The WTG area was constrained to a lower level than had been used in the initial survey. From Table 5.17-5, this area was selected to be less than 30 m^2. This was done to determine if the optimizer would be forced to add PV modules and/or batteries by itself in order to meet the load demand.

This upper limit was set at 27 m^2, being about 10% below the 30 m^2. This value was confirmed in a set of test optimizations using reduced costs. This constraint was then used for the remaining optimizations examined during this part of the investigation to provide a comparison between the various cases examined.

5.17.6.3. Results

The parameters for the runs for these systems are given in Table 5.17-12, with the results given in Table 5.17-13. Almost all of the cases examined resulted in systems which had significant numbers of PV modules and batteries. In particular, the systems using seasonal data required more PV modules, though generally similar numbers of batteries as those for the corresponding cases based on the total data set.

The prices of individual components and the fuel were reduced to determine which affects the system design the most.

One major difference between the results using each data set was noted. Those based on the seasonal data set required about 6 or 7 times as many PV modules as did those based on the total data set. This can be explained from Figure 5.17-1. The load demand is greater in the winter than in the summer, with significantly less PV module power available during that season. In order to contribute to meeting the load demand, since the WTG area is limited, more PV modules will be required. This, however, could lead to large amounts of excess power during the summer.

In each set of results, several cases had similar configurations. Those in which full prices were in effect required approximately the same number of PV modules and batteries as those cases for which the prices for only the WTG, batteries, and fuel were reduced. In addition, the capacities for the auxiliary generator, inverter, and rectifier were identical.

This indicates that the optimization algorithm, for the given constraints and load and weather data, is not sensitive to changes in these prices as the solutions for these cases are nearly equivalent.

Table 5.17-12. Parameters for Modified Edmonton Load 1 Runs

Parameter	Value
Nominal Constraints	
$A_{W_{MA}}$	27 m^2
$A_{W_{MIN}}$	0 m^2
$N_{S_{MAX}}$ (total)	50
$N_{S_{MAX}}$ (seasonal)	200
$N_{S_{MIN}}$ (total)	0
$N_{S_{MIN}}$ (seasonal)	0
$N_{B_{MAX}}$ (total)	50
$N_{B_{MAX}}$ (seasonal)	200
$N_{B_{MIN}}$ (total)	0
$N_{B_{MIN}}$ (seasonal)	0
$P_{G_{MAX}}$	2500 W
$P_{G_{MIN}}$	250 W
Starting Points	
A_W	25 m^2
N_S (total)	50
N_S (seasonal)	100
N_B (total)	30
N_B (seasonal)	30
Ranges	
N_S (total)	16.5
N_B (total)	7.5

All other ranges as given in Table 5.13-1

Table 5.17-13. Revised Results for Edmonton Load 1 ($N_{S_{MIN}}$ = 0, $N_{B_{MIN}}$ = 0)

Case							Results							
Load (W)	$N_{S_{MIN}}$	$N_{B_{MIN}}$	c_W (\$/m^2)	c_S (\$/mod.)	c_B (\$/A-hr/btty.)	c_F (\$/L)	A_W (m^2)	N_S	N_B	P_G^* (W)	P_I (W)	P_R (W)	f (L/day)	Cost (\$/yr)
						Total Data Set								
Mean	0	0	800	500	2.50	0.45	27.01	14	18	2500	1000	2000	0.91	6873
Mean	0	0	200	500	2.50	0.45	27.01	14	18	2500	1000	2000	0.91	4998
Mean	0	0	800	125	2.50	0.45	0.00	0	0	1500	0	0	6.37	3434
Mean	0	0	800	500	0.625	0.45	27.01	15	17	2500	1000	2000	0.89	5336
Mean	0	0	800	125	0.625	0.45	27.01	34	12	250	1000	1000	0.03	3979
Mean	0	0	800	500	2.50	0.30	27.01	14	18	2500	1000	2000	0.91	6806
Mean	0	0	200	125	0.625	0.30	27.01	30	12	500	1000	1000	0.07	2108
						Seasonal Data Set*								
Mean	0	0	800	500	2.50	0.45	27.01	91	16	2500	2000	1500	0.29	10914
Mean	0	0	200	500	2.50	0.45	27.01	93	15	2500	2000	1500	0.44	9057
Mean	0	0	800	125	2.50	0.45	27.01	101	14	2000	2000	1500	0.47	6879
Mean	0	0	800	500	0.625	0.45	27.01	91	16	2500	2000	1500	0.29	9525
Mean	0	0	800	125	0.625	0.45	27.01	117	21	500	2000	1000	0.04	5586
Mean	0	0	800	500	2.50	0.30	27.01	93	15	2500	2000	1500	0.44	10900
Mean	0	0	200	125	0.625	0.30	27.01	120	22	250	2500	1000	0.02	3778

*Seasonal fuel consumption average values

Most of the cases in Table 5.17-13 for which the PV module price was reduced also had similar configurations. The exception to this is the case, for the total data set, in which the only PV module price was reduced, yielding a system relying solely on the auxiliary generator. Results from earlier tests indicated that this would occur only when the PV module price was reduced between 20% and 76%.

For each data set, those cases in which both the PV module and battery prices were reduced also had similar results, with nearly similar numbers of PV modules and batteries being required. These cases also had the smallest required auxiliary generator capacities and the lowest fuel consumption rates, but also required the largest number of PV modules. This indicates that the optimization algorithm is sensitive to the prices of these two components, resulting in greater reliance on renewable energy sources, as the necessity for power from an auxiliary generator is not as great as for other cases.

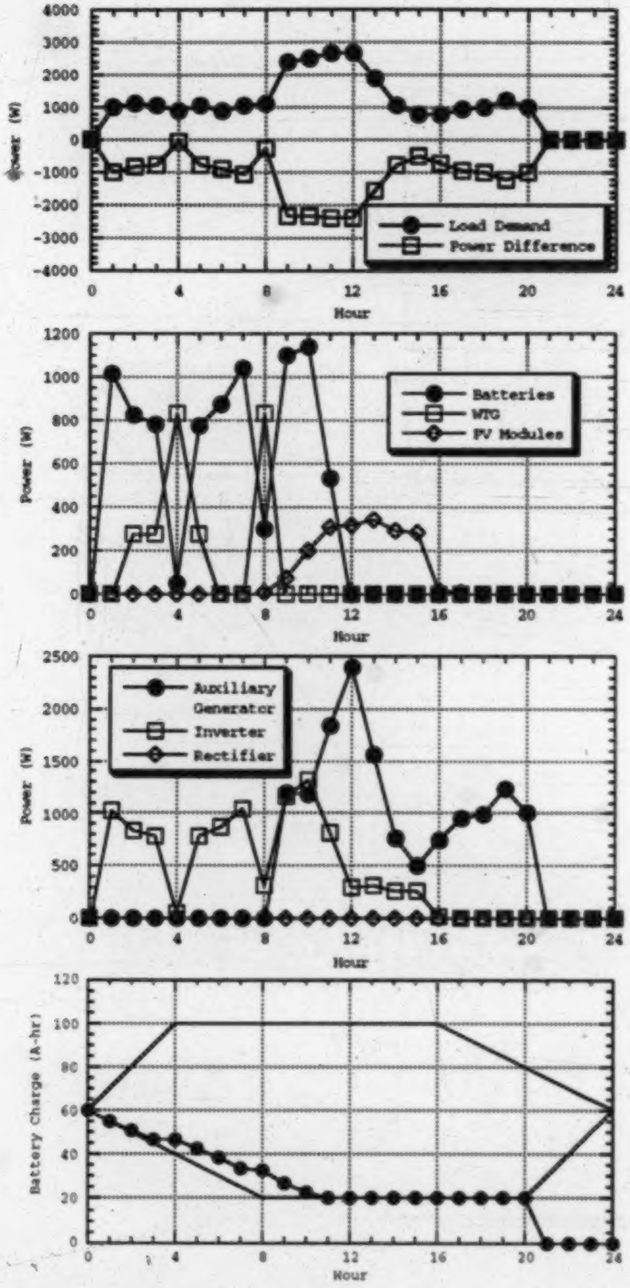
Also of note are the fuel requirements. When both the summer and winter data are combined, the daily fuel consumption is higher than when the data are separated into seasons. This is due, in part, to the systems being designed to provide power to the load primarily from the renewable sources and to utilize the auxiliary generator only when required. During the summer, more power from the renewable source is potentially available, reducing the dependence on the auxiliary generator. During the winter, as less power would be available from the renewable sources, the fuel consumption would increase.

This distinction between the seasons does not appear when the total data set is used. As a result, for a given hour, the same amount of renewable energy would be available throughout the year, which affects the fuel requirements.

5.17.6.4. Simulations

As had been done in 5.17.5., some of the results in Table 5.17-13 were evaluated. A number of days during the 20-year period from 1978 - 1997 were selected at random, and a hybrid renewable energy system based on some of the results evaluated.

As an example of how a renewable energy source might perform, one based on the first case (total data set) in Table 5.17-13 was tested simulating a day's operation. It was found that the system as designed was not able to complete the run, halting execution at about mid-evening (2000 hours), as is shown in Figure 5.17-6. It was ascertained that the capacity of the auxiliary generator would be exceeded due to it having to meet the load demand, and recharging the batteries, with the combined load it sees being well in excess of 3000 W.



A_w = 27.01 m^2 N_s = 14 N_p = 18

P_g^r = 2500 W P_i = 1000 W P_r = 2000 W

Figure 5.17-6. Run 1 for 1993, Day 329

The system was modified so that the auxiliary generator capacity was 5000 W and the simulation for that day run again. Execution was halted after 2300 hours and was due to the battery voltage being below the allowed minimum.

The run which produced this system was based on a maximum charge rate of *c*/10 for the lower half of the envelope. When the charge rate was decreased to *c*/10, the simulation using this system successfully completed execution for that day. Plots for this run are shown in Figure 5.17-7.

Changing the charge rate allowed the battery to charge at a slower rate. Doing so would prevent the violation of any applicable constraints as well as reducing the load on the auxiliary generator as less power would be required by the batteries.

It was noted that the inverter would have to produce a maximum output power of more than 1000 W, exceeding the capacity specified by the optimization algorithm, while the rectifier was well within its design limits.

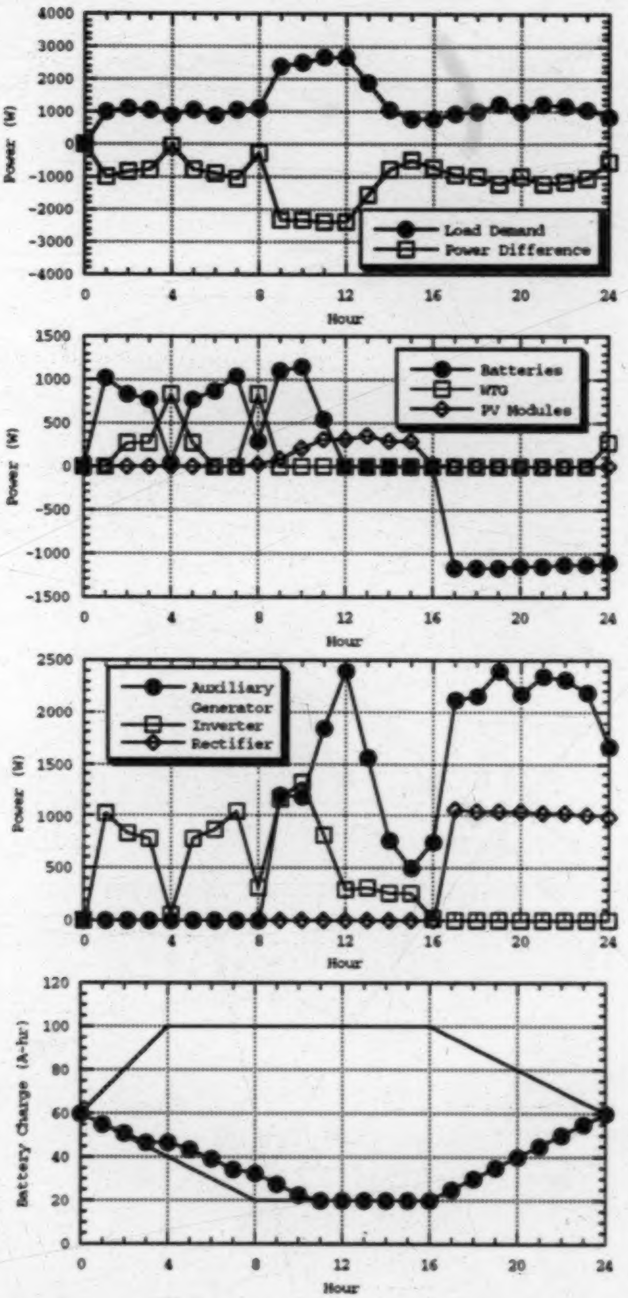
Figure 5.17-8 shows plots for a simulation run for the same day using a design based on seasonal effects and reduced prices, with failure occurring after 8 hours. By increasing the auxiliary generator capacity and reducing the lower envelope charge rate to *c*/20, the simulation was able to complete a run, the plots for which are given in Figure 5.17-9. However, the inverter power was nearly 2700 W.

As a comparison, Figure 5.17-10 shows the system from Figure 5.17-6 for different day. A large amount of excess power is available during the middle of the day, which allows for the charging of the battery to nearly full capacity. At the same time, the auxiliary generator is seldom used, providing less than 100 W of power. An inverter capacity greater than 1012 W is required.

As an additional evaluation of the Table 5.17-13 results, the times during which a system successfully operated were examined. Starting with the same initial conditions for each day, and using actual load and weather data, the number of days and the number of hours for each day during which the system operated were tallied. At the end of each day, the system is reset and the same initial conditions are used again.

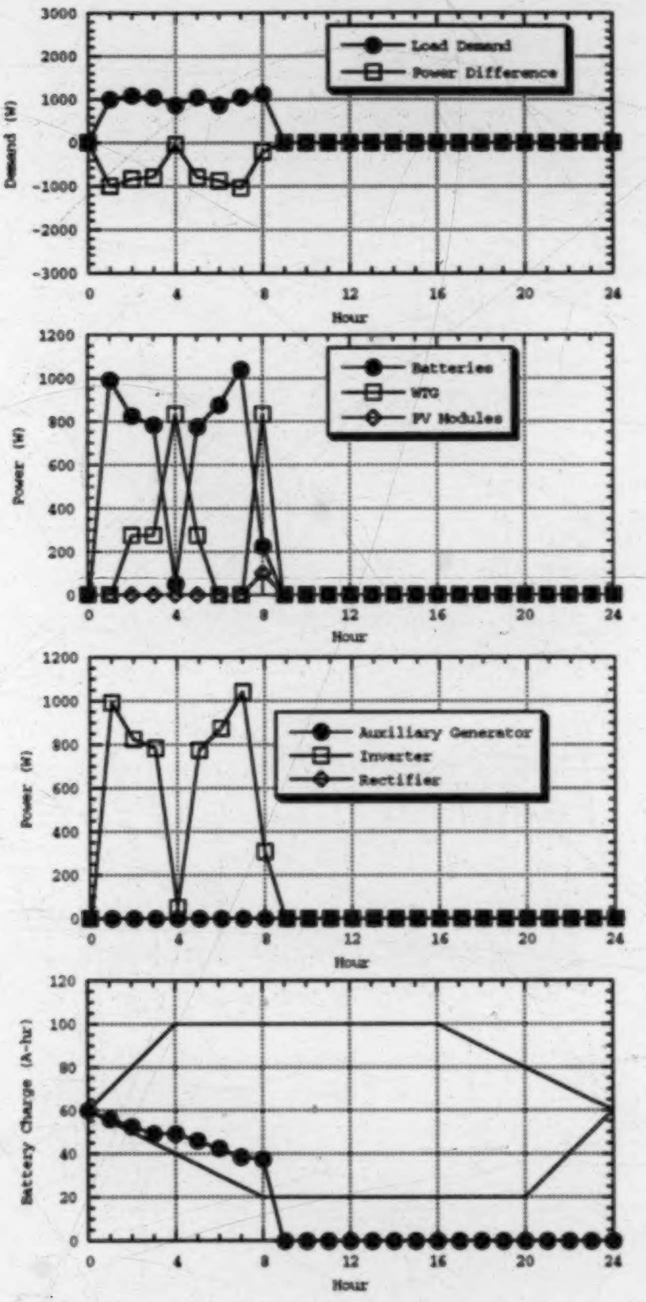
This was done for Edmonton Load 1 based on the optimization results in which both the summer and winter data were combined, with data for the calendar year of 1993 used.

The results are given in Table 5.17-14 and show that those



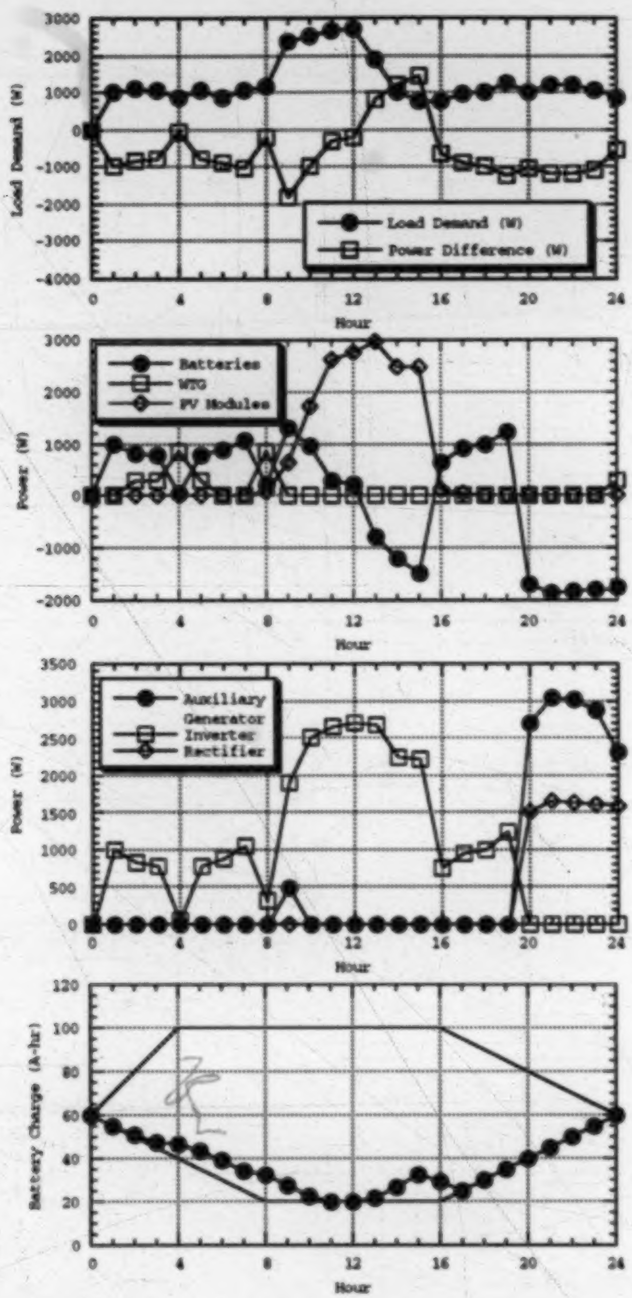
A_w = 27.01 m^2 N_s = 14 N_p = 18
P_R^r = 5000 W P_i = 1000 W P_g = 2000 W

Figure 5.17-7. Run 2 For 1993, Day 329



A_w = 27.01 m^2 N_s = 120 N_b = 22
P_G^r = 250 W P_i = 2500 W P_b = 1000 W

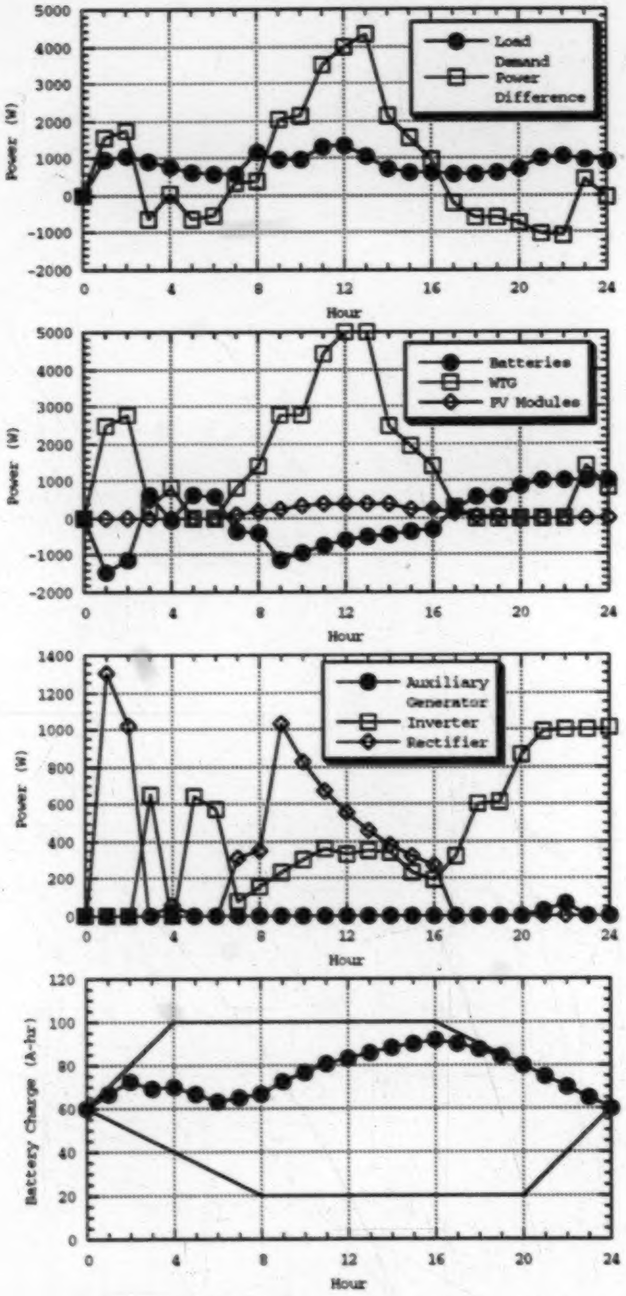
Figure 5.17-8. Run 3 for 1993, Day 329



A_c = 27.01 m^2 N_s = 120 N_b = 22

P_g^* = 5000 W P_i = 2500 W P_r = 1000 W

Figure 5.17-9. Run 4 for 1993, Day 329



A_a = 27.01 m^2 N_s = 14 N_b = 18
P_g^* = 2500 W P_i = 1000 W P_r = 2000 W

Figure 5.17-10. Run for 1988, Day 153

Table 5.17-14. Edmonton Load 1 Configuration Operating Times (1993)

Case							Results							
Load (W)	$N_{S_{MIN}}$	$N_{B_{MIN}}$	c_w ($/m^2)	c_S ($/mod.)	c_B ($/A-hr/btty.)	c_F ($/L)	A_w (m^2)	N_S	N_B	P_G^* (W)	P_I (W)	P_R (W)	Avg. Time (Hr./d)	Runs (D/yr)
						Total Data Set								
Mean	0	0	800	500	2.50	0.45	27.01	14	18	2500	1000	2000	17.1	18
Mean	0	0	200	500	2.50	0.45	27.01	14	18	2500	1000	2000	17.1	18
Mean	0	0	800	125	2.50	0.45	0.00	0	0	1500	0	0	0.8	0
Mean	0	0	800	500	0.625	0.45	27.01	15	17	2500	1000	2000	16.9	18
Mean	0	0	800	125	0.625	0.45	27.01	34	12	250	1000	1000	1.5	0
Mean	0	0	800	500	2.50	0.30	27.01	14	18	2500	1000	2000	17.1	18
Mean	0	0	200	125	0.625	0.30	27.01	30	12	500	1000	1000	1.9	0
						Seasonal Data Set								
Mean	0	0	800	500	2.50	0.45	27.01	91	16	2500	2000	1500	18.1	26
Mean	0	0	200	500	2.50	0.45	27.01	93	15	2500	2000	1500	18.0	28
Mean	0	0	800	125	2.50	0.45	27.01	101	14	2000	2000	1500	17.9	30
Mean	0	0	800	500	0.625	0.45	27.01	91	16	2500	2000	1500	18.1	26
Mean	0	0	800	125	0.625	0.45	27.01	117	21	500	2000	1000	5.2	16
Mean	0	0	800	500	2.50	0.30	27.01	93	15	2500	2000	1500	18.0	28
Mean	0	0	200	125	0.625	0.30	27.01	120	22	250	2500	1000	3.5	10

systems which require a larger auxiliary generator operated the longest, such as the case for which full market prices were in effect. For most of the cases, the simulation failed after about 17 hours and only 18 days had conditions which allowed a full day's operation.

As a comparison, a run using the data for the case for full prices with the total data set was made. The auxiliary generator capacity was increased to 5 kW. The results showed that the system operated, on average, for 22.9 hours per day and that 20 days of that year had conditions which allowed for a full day's operation. By changing the maximum charge rate in the evening from *c*/10 to *c*/15, the simulation operated for an average of 23.9 hours per day with 357 days of complete operation.

This indicates that the means by which the optimization algorithm determines the auxiliary generator capacity may require modification.

5.17.6.5. Interpretation of Simulation Results

These results indicate that the method for selecting the capacities for the auxiliary generator, inverter, and rectifier should be modified. One possibility is to increase the increments for the component capacities from 500 W to about 5000 W, as indicated from the simulations. Since this calculation is done after the actual optimization is completed, the algorithm can be readily modified to accommodate this.

Another characteristic of system performance is also shown by these results. Some of the simulation runs halted execution because a constraint was violated. One means by which this was solved was to adjust the rate at which the battery is charged from its minimum state of charge. This implies that the rate of charge could, in an operational setting, be changed by a controller, and that this could be done actively, based on existing conditions.

If the combined load seen by the auxiliary generator was due to the actual load demand plus the batteries, one possibility is some form of load shedding. This could involve disconnecting the batteries until more favourable conditions arise, disconnecting a non-essential part of the load itself, or a combination of both. Once again, this could be handled by a controller.

The constraints for the optimization algorithm could also be modified so that a minimum number of PV modules and batteries would be present in the system. From Table 5.17-13, the smallest number of PV modules and batteries were 14 and 12, respectively. A lower limit of at least 10 for each should cause the optimization algorithm, using this load data, to yield results for a system with sufficient capacity, for the given WTG area, which would meet the load demand.

5.17.6.6. Capacity Revisions

Revising how the auxiliary generator, inverter, and rectifier capacities are determined resulted in the values shown in Table 5.17-15. An algorithm using only the procedure for optimizing the battery was used, with the values for A_w, N_s, and N_b used as input as only the method described in 5.8.3.11. was modified.

Comparing Tables 5.17-13 and 5.17-15, those cases which initially had the smallest auxiliary generator, inverter, and rectifier capacities had the greatest proportional increases in annual cost. For example, when all the applicable prices for the results (based on the total data set) were reduced, the system cost nearly doubled from \$2108 to \$4168. In addition, the increase in fuel consumption rates can be explained in how it was modelled in (5.8.3-7), being taken as linearly proportional to the required auxiliary generator capacity. Comparing the results based on the seasonal data set, no such large increases were noted.

Table 5.17-16 shows the installed cost based on the results in Table 5.17-15. In addition, this table shows the equivalent lengths for a utility line that could be obtained for those costs based on \$20000/km, as given in [1]. Based on most of the results in Table 5.17-16, a utility line must be at least 1.5 kilometres away from the load in order for the systems to be considered a valid economic alternative. In remote locations, this situation could likely occur.

For most of the systems in 5.17-16, the variations in the installed costs are due to the reduction in the price of one of the components, since the designs themselves are similar. Only when full price reductions are applied does the installed cost drop to a low level. This is also noted in Table 5.17-16.

Another basis for comparing the costs is the annual equivalent capital and operating cost for the utility lines in Table 5.17-16.

These costs were calculated by multiplying the installed costs by (5.9.4-2) and adding on the annual power cost. The daily energy requirement was estimated to be about 24 kWh (based on mean hourly values), with the power cost estimated at about \$0.07/kWh [158]. No salvage was assumed. The

Table 5.17-15. Revised Table 5.17-13 Results

Case							Results								
Load (W)	$N_{S_{MIN}}$	$N_{B_{MIN}}$	C_W (\$/m^2)	C_S (\$/mod.)	C_B (\$/A-hr/btty.)	C_F (\$/L)	A_W (m^2)	N_S	N_B	P_G^* (W)	P_I (W)	P_R (W)	f (L/day)	Cost (\$/yr)
							Total Data Set							
Mean	0	0	800	500	2.50	0.45	27.01	14	18	5000	5000	5000	1.81	8460
Mean	0	0	200	500	2.50	0.45	27.01	14	18	5000	5000	5000	1.81	6585
Mean	0	0	800	125	2.50	0.45	0.00	0	0	5000	0	0	21.23	11170
Mean	0	0	800	500	0.625	0.45	27.01	15	17	5000	5000	5000	1.78	6920
Mean	0	0	800	125	0.625	0.45	27.01	34	12	5000	5000	5000	0.64	6137
Mean	0	0	800	500	2.50	0.30	27.01	14	18	5000	5000	5000	1.81	8327
Mean	0	0	200	125	0.625	0.30	27.01	30	12	5000	5000	5000	0.70	4168
							Seasonal Data Set*							
Mean	0	0	800	500	2.50	0.45	27.01	91	16	5000	5000	5000	0.54	11163
Mean	0	0	200	500	2.50	0.45	27.01	93	15	5000	5000	5000	0.85	9871
Mean	0	0	800	125	2.50	0.45	27.01	101	14	5000	5000	5000	1.15	7752
Mean	0	0	800	500	0.625	0.45	27.01	91	16	5000	5000	5000	0.54	10274
Mean	0	0	800	125	0.625	0.45	27.01	117	21	5000	5000	5000	0.33	6420
Mean	0	0	800	500	2.50	0.30	27.01	93	15	5000	5000	5000	0.85	11683
Mean	0	0	200	125	0.625	0.30	27.01	120	22	5000	5000	5000	0.00	4497

*Seasonal fuel consumption average values

Table 5.17-16. Edmonton Load 1 Installation Costs and Line Lengths

Case						Results							
Load (W)	$N_{S_{MIN}}$	$N_{B_{MIN}}$	C_W ($/m^2)	C_S ($/mod.)	C_B ($/A-hr/btty.)	A_W (m^2)	N_S	N_B	P_G^* (W)	P_I (W)	P_R (W)	Installed Cost ($)	Length (km)
						Total Data Set							
Mean	0	0	800	500	2.50	27.01	14	18	5000	5000	5000	53105	2.7
Mean	0	0	200	500	2.50	27.01	14	18	5000	5000	5000	36901	1.8
Mean	0	0	800	125	2.50	0.00	0	0	5000	0	0	10000	0.5
Mean	0	0	800	500	0.625	27.01	15	17	5000	5000	5000	50167	2.5
Mean	0	0	800	125	0.625	27.01	34	12	5000	5000	5000	46605	2.3
Mean	0	0	800	500	2.50	27.01	14	18	5000	5000	5000	31500	1.6
Mean	0	0	200	125	0.625	27.01	30	12	5000	5000	5000	29901	1.5
						Seasonal Data Set							
Mean	0	0	800	500	2.50	27.01	91	16	5000	5000	5000	91105	4.6
Mean	0	0	200	500	2.50	27.01	93	15	5000	5000	5000	75651	3.8
Mean	0	0	800	125	2.50	0.00	101	14	5000	5000	5000	57730	2.9
Mean	0	0	800	500	0.625	27.01	91	16	5000	5000	5000	88105	4.4
Mean	0	0	800	125	0.625	27.01	117	21	5000	5000	5000	57542	2.9
Mean	0	0	800	500	2.50	27.01	93	15	5000	5000	5000	91855	4.6
Mean	0	0	200	125	0.625	27.01	120	22	5000	5000	5000	41776	2.1

results are given in Table 5.17-17.

Comparing Tables 5.17-15 and 5.17-17, renewable energy system costs based on the total data set were higher. Only when all prices were reduced was a system cheaper than a utility line. The costs for most of the systems based on seasonal data, on the other hand, were lower.

It is emphasized that the comparison is based on revised optimization results. Should the algorithm use a smaller auxiliary generator (say, 3 kW), the corresponding costs in Table 5.17-15 will be lower. If a proposed utility line was longer than the distances indicated in Table 5.17-16, those costs will be higher.

5.17.7. Assessment and Recommended Application Strategy

All of the results in Tables 5.17-13 are feasible from an optimization standpoint, but may not necessarily yield a good design. Some of these shortcomings included large amounts of excess power and operational limitations.

Systems which have a large weighting in one of the renewable energy sources would not be suitable for a stand-alone system for this load (such as those based on seasonal data in Table 5.17-15) due to the large amounts of unused excess power that will be produced and the randomness in weather and load conditions. A system such as the first one (total data set) in Table 5.17-15 would be preferable from that perspective.

Optimizations based on a starting point with higher numbers of PV modules and batteries generally produced systems that included both. This aspect could be used in applying the optimization method to other loads in the Edmonton area as well as loads at other locations as the results could be used in designing a renewable energy system.

5.18. Edmonton Load 2

5.18.1. Symbols

A_w = wind turbine generator rotor area (m^2)
$A_{w_{max}}$ = maximum wind turbine generator rotor area (m^2)
$A_{w_{min}}$ = minimum wind turbine generator rotor area (m^2)
c_b = battery cost (\$/A-hr/battery)
c_f = fuel cost (\$/L)
c_s = photovoltaic module cost (\$/module)
c_w = wind turbine cost (\$/m^2)
f = auxiliary generator fuel consumption rate (L/day)
N_b = number of batteries
$N_{b_{max}}$ = maximum number of batteries

Table 5.17-17. Edmonton Load 1 Power Line Costs

Case						Results							
Load (W)	$N_{s_{MIN}}$	$N_{p_{MIN}}$	c_w ($/m^2)	c_s ($/mod.)	c_B ($/A-hr/btty.)	A_w (m^2)	N_s	N_p	P_G^* (W)	P_I (W)	P_R (W)	Length (km)	Cost ($/yr)
						Total Data Set							
Mean	0	0	800	500	2.50	27.01	14	18	5000	5000	5000	2.7	6850
Mean	0	0	200	500	2.50	27.01	14	18	5000	5000	5000	1.8	4947
Mean	0	0	800	125	2.50	0.00	0	0	5000	0	0	0.5	1787
Mean	0	0	800	500	0.625	27.01	15	17	5000	5000	5000	2.5	6505
Mean	0	0	800	125	0.625	27.01	34	12	5000	5000	5000	2.3	6087
Mean	0	0	800	500	2.50	27.01	14	18	5000	5000	5000	1.6	4312
Mean	0	0	200	125	0.625	27.01	30	12	5000	5000	5000	1.5	4125
						Seasonal Data Set*							
Mean	0	0	800	500	2.50	27.01	91	16	5000	5000	5000	4.6	11314
Mean	0	0	200	500	2.50	27.01	93	15	5000	5000	5000	3.8	9498
Mean	0	0	800	125	2.50	27.01	101	14	5000	5000	5000	2.9	7393
Mean	0	0	800	500	0.625	27.01	91	16	5000	5000	5000	4.4	10961
Mean	0	0	800	125	0.625	27.01	117	21	5000	5000	5000	2.9	7371
Mean	0	0	800	500	2.50	27.01	93	15	5000	5000	5000	4.6	11402
Mean	0	0	200	125	0.625	27.01	120	22	5000	5000	5000	2.1	5519

Costs based on 24 kWh/day, 10% annual interest rate, and $0.07/kWh [158]

$N_{B_{MIN}}$ = minimum number of batteries
N_S = number of photovoltaic modules
$N_{S_{MAX}}$ = maximum number of photovoltaic modules
$N_{S_{MIN}}$ = minimum number of photovoltaic modules
P_G^* = required auxiliary generator capacity (W)
$P_{G_{MAX}}$ = maximum auxiliary generator capacity (W)
$P_{G_{MIN}}$ = minimum auxiliary generator capacity (W)
P_I = inverter capacity (W)
P_R = rectifier capacity (W)

5.18.2. Load Description

In this part of the investigation, another load in the Edmonton area was examined. As with the previous load, details on what the data may represent were unavailable.

Histograms for the load data are shown in Figure 5.18-1. The data range from zero to over 12 kW and display a distinctly seasonal behaviour. According to Table 5.18-1, the larger loads occur during winter when there are higher wind speeds and/or lower temperatures, most occurring at about mid-evening. Such large increases in seasonal loads during winter are possibly due to activities inside farm buildings such as maintenance shops, though another possibility is that these are loads due to the heating of stock barns [159].

5.18.3. Initial Optimization Results

5.18.3.1. General

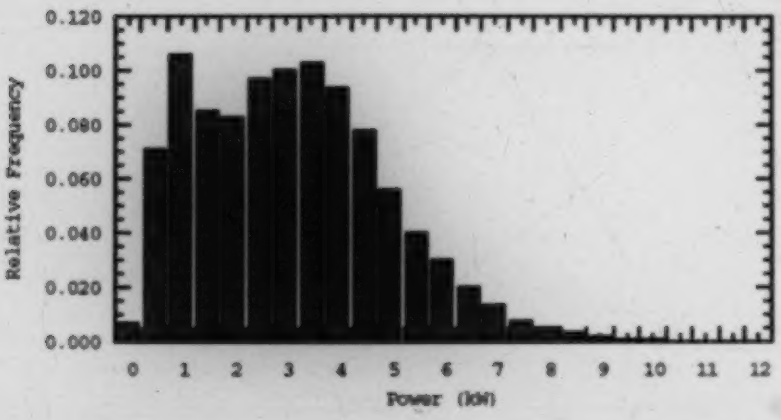
As had been done in 5.17.4., an initial survey for a set of maximum loads was conducted. The constraints for this survey are given in Table 5.18-2 and the starting points in Table 5.18-3.

5.18.3.2. Loads

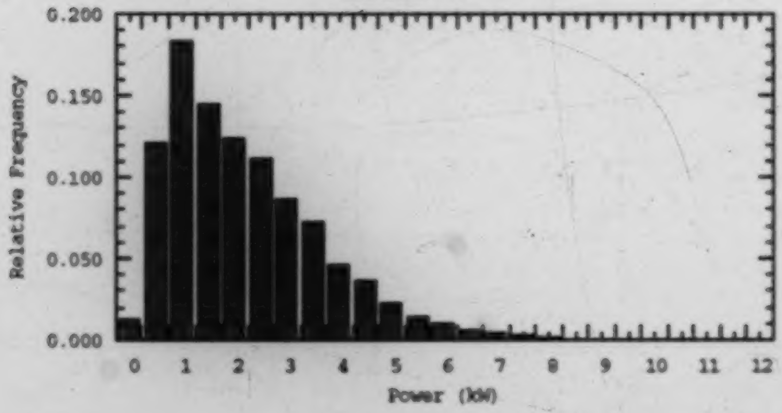
To approximate conditions such as load-shedding, the maximum load for each hour was reduced from 100% of the historical values down to 6000 W in 2000 W increments, with mean loads included for comparison. These loads are shown in Figure 5.18-2.

5.18.3.3. System Configurations

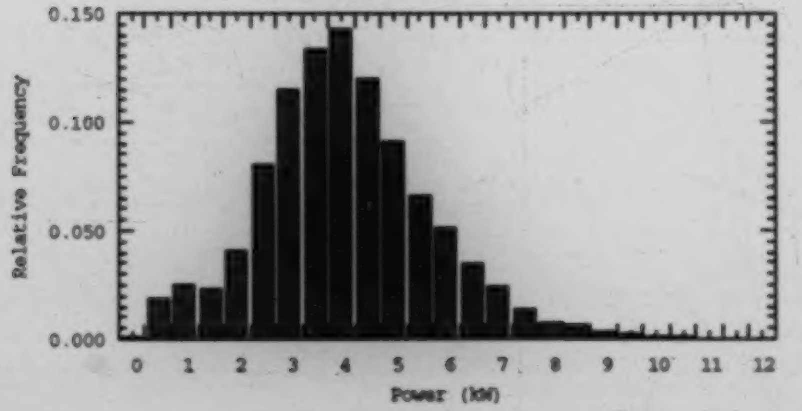
The results of the initial survey are presented in Tables 5.18-4 - 5.18-11. In general, the results are similar to those obtained for the previous load in 5.17.4, with a few exceptions.



Total



Summer



Winter

Figure 5.18-1. Edmonton Load 2 Histograms (5 years)

Table 5.18-1. Conditions for Edmonton Load 2 Demands Above 10500 W

Date	Hour	Temp. (°C)	Wind (km/hr)	Raid. (W/m^2)	Load (W)
1993-01-08	20	-23.30	0.00	0.00	10717
1993-01-21	18	-2.80	7.00	0.00	10793
1993-01-21	19	-3.60	9.00	0.00	11236
1993-02-04	16	-8.40	7.00	60.32	11603
1993-02-04	17	-8.10	6.00	10.64	11344
1993-02-05	9	-7.90	15.00	21.03	10602
1993-02-14	21	-17.40	11.00	0.00	10739
1993-02-14	22	-18.10	13.00	0.00	11070
1993-02-15	17	-15.10	22.00	25.35	12330
1993-02-15	18	-16.00	15.00	0.49	11495
1993-02-23	14	-11.10	11.00	919.56	10944
1993-12-29	19	1.50	15.00	0.00	11084
1994-01-04	18	-23.40	19.00	0.00	11628
1994-01-10	21	-22.40	17.00	0.00	10667
1994-01-16	20	-23.80	19.00	0.00	11815
1994-01-16	21	-23.90	19.00	0.00	12071
1994-01-18	13	-17.60	19.00	210.11	11534
1994-01-18	14	-17.20	13.00	271.68	11448
1994-01-24	20	-9.70	11.00	0.00	11444
1994-01-29	18	-3.40	11.00	0.00	10634
1994-01-29	19	-3.40	11.00	0.00	11639
1994-02-08	15	-18.70	0.00	792.85	10613
1994-02-15	21	-12.60	17.00	0.00	11714
1994-02-21	18	-21.60	17.00	1.99	11563
1994-02-21	19	-22.00	17.00	0.00	10832
1994-02-21	20	-22.20	17.00	0.00	11088
1994-02-21	21	-22.30	13.00	0.00	10843
1994-02-27	12	-17.20	13.00	829.27	11084
1994-03-08	20	1.40	7.00	0.00	11315
1994-12-09	19	-21.90	4.00	0.00	12146
1996-11-24	18	-20.70	7.00	0.00	12226
1996-11-24	19	-21.00	6.00	0.00	10732
1996-12-24	10	-27.20	7.00	413.36	10861
1997-01-09	10	-28.60	9.00	515.58	11833
1997-01-09	11	-27.20	11.00	768.83	10692
1997-01-09	12	-26.50	11.00	892.79	11196
1997-02-27	11	-6.30	4.00	214.31	10850
1997-03-14	16	-11.40	6.00	636.02	11070

Table 5.18-2. Constraints and Limits for Edmonton Load 2 Initial Survey

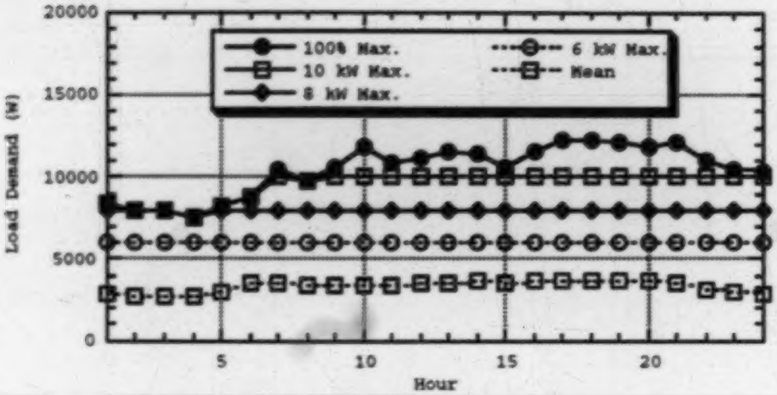
Parameter	Value
$A_{W_{MAX}}$	305 m^2
$A_{W_{MIN}}$	0 m^2
$N_{S_{MAX}}$	500
$N_{S_{MIN}}$	0, 10
$N_{B_{MAX}}$	500
$N_{B_{MIN}}$	0, 10
$P_{G_{MAX}}$	5000 W
$P_{G_{MIN}}$	250 W

Table 5.18-3. Starting Points for Edmonton Load 2 Initial Survey

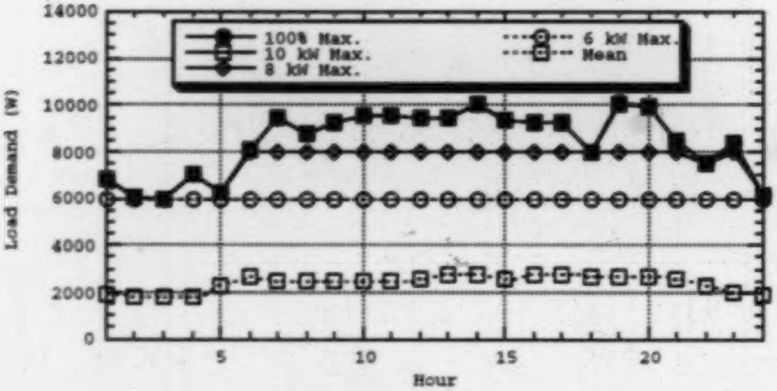
	Full Prices			Reduced Prices		
Load (kW)	A_W (m^2)	N_S	N_B	A_W (m^2)	N_S	N_B
	$N_{S_{MIN}} = 0/N_{B_{MIN}} = 0$ (Total Data Set)					
100%	300	50	15	300	50	15
10	300	50	15	300	50	15
8	300	50	15	300	50	15
6	300	50	15	300	50	15
Mean	300	50	15	300	50	15
	$N_{S_{MIN}} = 0/N_{B_{MIN}} = 10$ (Total Data Set)					
100%	300	50	15	300	50	15
10	300	50	15	300	50	15
8	300	50	15	300	50	15
6	300	50	15	300	50	15
Mean	300	50	15	300	50	15
	$N_{S_{MIN}} = 10/N_{B_{MIN}} = 0$ (Total Data Set)					
100%	300	50	15	300	50	15
10	300	50	15	300	50	15
8	300	50	15	300	50	15
6	300	50	15	300	50	15
Mean	300	50	15	300	50	15
	$N_{S_{MIN}} = 10/N_{B_{MIN}} = 10$ (Total Data Set)					
100%	300	50	15	300	50	15
10	300	50	15	300	50	15
8	300	50	15	300	50	15
6	300	50	15	300	50	15
Mean	300	50	15	300	50	15

Table 5.18-3. Starting Points for Edmonton Load 2 Initial Survey (Cont'd)

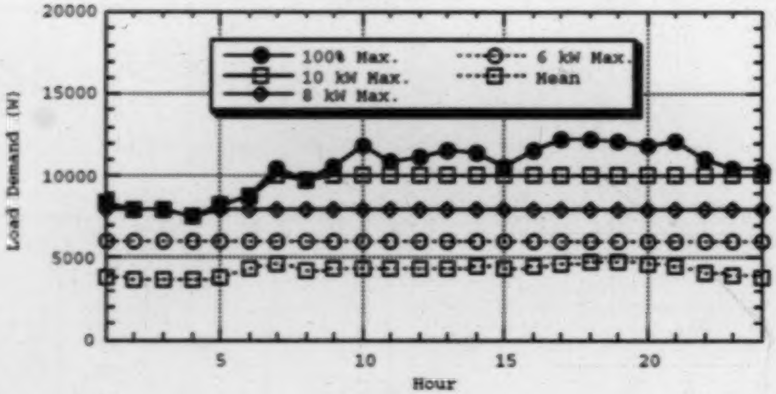
	Full Prices			Reduced Prices		
Load (W)	A_W (m^2)	N_S	N_B	A_W (m^2)	N_S	N_B
	$N_{S_{MIN}} = 0/N_{B_{MIN}} = 0$ (Seasonal Data Set)					
100%	301	50	0	301	50	0
10	300	50	0	300	50	0
8	300	50	15	300	50	15
6	300	50	15	300	50	15
Mean	300	50	15	300	50	15
	$N_{S_{MIN}} = 0/N_{B_{MIN}} = 10$ (Seasonal Data Set)					
8	300	50	15	300	50	15
6	300	50	15	300	50	15
Mean	300	50	15	300	50	15
	$N_{S_{MIN}} = 10/N_{B_{MIN}} = 0$ (Seasonal Data Set)					
100%	301	50	0	301	50	0
10	300	50	0	300	50	0
8	300	50	15	300	50	15
6	300	50	15	300	50	15
Mean	300	50	15	300	50	15
	$N_{S_{MIN}} = 10/N_{B_{MIN}} = 10$ (Seasonal Data Set)					
8	300	50	15	300	50	15
6	300	50	15	300	50	15
Mean	300	50	15	300	50	15



Total



Summer



Winter

Figure 5.18-2. Maximum Load Demand for Edmonton Load 2

Table 5.18-4. Initial Optimization Results for Edmonton Load 2 ($N_{S_{MIN}}$ = 0, $N_{P_{MIN}}$ = 0, Total Data Set)

Case							Results							
Load (kW)	$N_{S_{MIN}}$	$N_{P_{MIN}}$	C_W (\$/m^2)	C_S (\$/mod.)	C_B (\$/A-hr/btty.)	C_F (\$/L)	A_W (m^2)	N_S	N_P	P_G^* (W)	P_I (W)	P_R (W)	f (L/day)	Cost (\$/yr)
100%	0	0	800	500	2.50	0.45	288.8	0	4	4500	500	500	18.63	39457
10	0	0	800	500	2.50	0.45	268.0	0	4	4000[a]	500	500	15.53	36110
8	0	0	800	500	2.50	0.45	230.6	0	15	2500	1000	2000	7.59	30180
6	0	0	800	500	2.50	0.45	129.8	0	0	3500	0	0	16.65	21212
Mean	0	0	800	500	2.50	0.45	10.4	0	0	3500	0	0	23.64	11121
100%	0	0	200	125	0.625	0.30	304.3	0	7	4000	500	1000	14.78	17323
10	0	0	200	125	0.625	0.30	297.1	0	53	500	3500	5000	0.15	13307
8	0	0	200	125	0.625	0.30	249.3	1	43	500	3000	4500	0.27	11281
6	0	0	200	125	0.625	0.30	192.2	0	30	500	2000	3500	0.34	8679
Mean	0	0	200	125	0.625	0.30	102.8	0	17	500	1500	2000	0.14	4723

Table 5.18-5. Initial Optimization Results for Edmonton Load 2 ($N_{s_{MIN}}$ = 0, $N_{B_{MIN}}$ = 10, Total Data Set)

			Case				Results							
Load (kW)	$N_{s_{MIN}}$	$N_{B_{MIN}}$	C_w (\$/m^2)	C_s (\$/mod.)	C_B (\$/A-hr/btty.)	C_f (\$/L)	A_w (m^2)	N_s	N_B	P_G^* (W)	P_I (W)	P_B (W)	f (L/day)	Cost (\$/yr)
100%	0	10	800	500	2.50	0.45	297.1	0	10	4500	1000	1500	16.86	40773
10	0	10	800	500	2.50	0.45	279.4	0	10	3500	1000	1500	11.99	36893
8	0	10	800	500	2.50	0.45	226.4	0	10	3000	1000	1500	10.28	30476
6	0	10	800	500	2.50	0.45	171.4	1	12	2000	1000	1500	5.48	22702
Mean	0	10	800	500	2.50	0.45	101.8	0	12	1000	1000	1500	0.87	13061
100%	0	10	200	125	0.625	0.30	300.2	0	10	4000	1000	1500	14.72	17366
10	0	10	200	125	0.625	0.30	297.1	2	53	500	3500	5000	0.14	13335
8	0	10	200	125	0.625	0.30	247.2	0	45	500	3000	4500	0.27	11248
6	0	10	200	125	0.625	0.30	184.9	1	33	500	2000	3500	0.47	8540
Mean	0	10	200	125	0.625	0.30	102.8	0	17	500	1500	2000	0.14	4723

Table 5.18-6. Initial Optimization Results for Edmonton Load 2 ($N_{s_{min}}$ = 10, $N_{p_{min}}$ = 0, Total Data Set)

			Case				Results							
Load (kW)	$N_{s_{min}}$	$N_{p_{min}}$	C_w (\$/m^2)	C_s (\$/mod.)	C_b (\$/A-hr/btty.)	C_f (\$/L)	A_w (m^2)	N_s	N_p	P_G^* (W)	P_I (W)	P_B (W)	f (L/day)	Cost (\$/yr)
100%	10	0	800	500	2.50	0.45	286.7	10	5	4500	500	1000	18.63	39992
10	10	0	800	500	2.50	0.45	268.0	10	4	4000	500	500	15.47	36675
8	10	0	800	500	2.50	0.45	189.0	10	2	4500	250	250	21.47	30444
6	10	0	800	500	2.50	0.45	141.3	11	1	3500	250	250	14.53	22725
Mean	10	0	800	500	2.50	0.45	10.4	10	0	3500	250	0	23.46	11682
100%	10	0	200	125	0.625	0.45	303.3	10	7	4000	500	1000	14.82	17437
10	10	0	200	125	0.625	0.30	296.0	10	53	500	3500	5000	0.15	13414
8	10	0	200	125	0.625	0.30	246.2	11	44	500	3000	4500	0.28	11343
6	10	0	200	125	0.625	0.30	184.9	10	35	250	2500	3500	0.13	8587
Mean	10	0	200	125	0.625	0.30	101.8	10	17	500	1500	2000	0.14	4831

Table 5.18-7. Initial Optimization Results for Edmonton Load 2 ($N_{S_{MIN}}$ = 10, $N_{B_{MIN}}$ = 10, Total Data Set)

Case							Results							
Load (kW)	$N_{S_{MIN}}$	$N_{B_{MIN}}$	C_W (\$/m^2)	C_S (\$/mod.)	C_B (\$/A-hr/btty.)	C_F (\$/L)	A_W (m^2)	N_S	N_B	P_G^* (W)	P_I (W)	P_R (W)	f (L/day)	Cost (\$/yr)
100%	10	10	800	500	2.50	0.45	297.1	10	10	4500	1000	1500	16.80	41335
10	10	10	800	500	2.50	0.45	290.8	10	17	3000	1500	2000	8.38	37948
8	10	10	800	500	2.50	0.45	217.1	10	10	3500	1000	1500	12.65	31075
6	10	10	800	500	2.50	0.45	168.3	10	10	2500	1000	1500	7.47	23809
Mean	10	10	800	500	2.50	0.45	101.8	10	12	1000	1000	1500	0.86	13635
100%	10	10	200	125	0.625	0.30	303.3	11	10	4000	1000	1500	14.38	17579
10	10	10	200	125	0.625	0.30	299.1	10	51	500	3500	5000	0.14	13465
8	10	10	200	125	0.625	0.30	241.0	11	33	1500	2500	4000	2.74	11990
6	10	10	200	125	0.625	0.30	179.7	21	26	1000	2000	3000	1.70	9050
Mean	10	10	200	125	0.625	0.30	101.8	12	17	500	1500	2000	0.14	4860

Table 5.18-8. Initial Optimization Results for Edmonton Load 2 ($N_{S_{MIN}}$ = 0, $N_{B_{MIN}}$ = 0, Seasonal Data Set)

				Case						Results				
Load (kW)	$N_{S_{MIN}}$	$N_{B_{MIN}}$	C_W (\$/m^2)	C_S (\$/mod.)	C_B (\$/A-hr/btty.)	C_F (\$/L)	A_W (m^2)	N_S	N_B	P_G^* (W)	P_I (W)	P_R (W)	f_c (L/day)	Cost (\$/yr)
100%	0	0	800	500	2.50	0.45	301.2	0	0	5000	0	0	16.50	39554
10	0	0	800	500	2.50	0.45	250.3	0	0	5000	0	0	21.34	35558
8	0	0	800	500	2.50	0.45	150.6	0	0	5000	0	0	31.62	28929
6	0	0	800	500	2.50	0.45	109.1	0	0	4000	0	0	23.12	21278
Mean	0	0	800	500	2.50	0.45	161.0	0	4	1000	500	500	0.95	18175
100%	0	0	200	125	0.625	0.30	301.2	0	0	5000	0	0	16.50	17427
10	0	0	200	125	0.625	0.30	294.0	0	0	4000	0	0	11.50	14924
8	0	0	200	125	0.625	0.30	301.2	0	31	250	2000	3500	0.05	12376
6	0	0	200	125	0.625	0.30	229.6	0	20	250	1500	2500	0.15	9362
Mean	0	0	200	125	0.625	0.30	162.0	0	7	1000	500	1000	0.65	6540

Table 5.18-9. Initial Optimization Results for Edmonton Load 2 ($N_{S_{MIN}}$ = 0, $N_{B_{MIN}}$ = 10, Seasonal Data Set)

Case							Results							
Load (kW)	$N_{S_{MIN}}$	$N_{B_{MIN}}$	c_W (\$/m^2)	c_S (\$/mod.)	c_B (\$/A-hr/btty.)	c_F (\$/L)	A_W (m^2)	N_S	N_B	P_G^* (W)	P_I (W)	P_B (W)	ξ (L/day)	Cost (\$/yr)
8	0	10	800	500	2.50	0.45	280.4	0	10	3000	1000	1500	5.57	34134
6	0	10	800	500	2.50	0.45	219.2	0	10	2000	1000	1500	3.77	26602
Mean	0	10	800	500	2.50	0.45	157.9	0	10	1500	1000	1500	0.97	18701
8	0	10	200	125	0.625	0.30	300.2	0	32	250	2000	4000	0.03	12421
6	0	10	200	125	0.625	0.30	229.6	0	20	250	1500	2500	0.15	9362
Mean	0	10	200	125	0.625	0.30	162.0	0	10	1000	1000	1500	0.49	6656

Table 5.18-10.* Initial Optimization Results for Edmonton Load 2 ($N_{s_{MIN}}$ = 10, $N_{b_{MIN}}$ = 0, Seasonal Data Set)

Case							Results							
Load (kW)	$N_{s_{MIN}}$	$N_{b_{MIN}}$	c_w (\$/m^2)	c_s (\$/mod.)	c_b (\$/A-hr/btty.)	c_f (\$/L)	A_w (m^2)	N_s	N_b	P_G^* (W)	P_I (W)	P_R (W)	f (L/day)	Cost (\$/yr)
100%	10	0	800	500	2.50	0.45	301.2	10	0	5000	250	0	16.44	40147
10	0	0	800	500	2.50	0.45	250.3	10	0	5000	250	0	21.26	36147
8	10	0	800	500	2.50	0.45	148.5	10	0	5000	250	0	31.77	29396
6	10	0	800	500	2.50	0.45	105.9	10	0	4000	250	0	23.63	21742
Mean	10	0	800	500	2.50	0.45	154.8	10	13	2000	1000	1500	1.03	19448
100%	10	0	200	125	0.625	0.30	303.3	10	0	5000	250	0	16.27	17597
10	10	0	200	125	0.625	0.30	294.0	10	0	4000	250	0	11.46	15091
8	10	0	200	125	0.625	0.30	300.2	10	31	500	2000	3500	0.13	12516
6	10	0	200	125	0.625	0.30	228.5	10	20	250	250	1500	0.15	9470
Mean	10	0	200	125	0.625	0.30	161.0	10	8	1000	1000	1000	0.64	6725

Table 5.18-11. Initial Optimization Results for Edmonton Load 2 ($N_{S_{MIN}}$ = 10, $N_{B_{MIN}}$ = 10, Seasonal Data Set)

Case							Results							
Load (kW)	$N_{S_{MIN}}$	$N_{B_{MIN}}$	c_W (\$/m^2)	c_S (\$/mod.)	c_B (\$/A-hr/btty.)	c_F (\$/L)	A_W (m^2)	N_S	N_B	P_G^* (W)	P_I (W)	P_R (W)	f (L/day)	Cost (\$/yr)
8	10	10	800	500	2.50	0.45	279.4	10	10	3000	1000	1500	5.59	34624
6	10	10	800	500	2.50	0.45	230.6	10	13	1000	1000	1500	1.21	27271
Mean	10	10	800	500	2.50	0.45	154.8	10	13	2000	1000	1500	1.03	19448
8	10	10	200	125	0.625	0.30	300.2	10	31	500	2000	3500	0.13	12516
6	10	10	200	125	0.625	0.30	234.7	10	16	500	1000	2000	0.30	9524
Mean	10	10	200	125	0.625	0.30	161.0	10	14	500	1000	1000	0.14	6712

For example, the maximum load demand for this case is about three times higher than that for that in Tables 5.17-4 - 5.17.11, with the costs and required capacities, in general, correspondingly greater. All of the systems examined required WTG's while most required batteries, unlike what had been observed for the previous load.

One reason for this might be seen in the load's seasonal characteristics. From Figure 5.18-1, the load demand is much higher in winter when less power is available from the PV modules. In order to contribute to meeting the load demand in the winter, a larger number of PV modules will be required than would be needed in the summer. Should a renewable energy system be designed on the basis of the number of modules required during the winter, excess power may be present during the summer, resulting in under-used capacity. It is likely, therefore, that a system using WTG's and batteries may more effectively meet the load demand throughout the year.

5.18.4. Revisions to Method

5.18.4.1. Load

As had been done in 5.17.6., the mean load was selected for further analysis with the optimizations using a higher number of PV modules and batteries. This was chosen because the seasonal difference between the mean load demands for summer and winter is proportionally much greater than what had been observed in 5.17.

5.18.4.2. Results

The constraints and starting points for this set of runs are given in Table 5.18-12.

Table 5.18-13 is a comparison of results for cases using the total and seasonal data sets at full market prices, but with the same nominal maximum WTG area. The value of 60 m^2 was chosen after experimenting with a variety of areas.

The case based on seasonal data had a considerably different design and a correspondingly higher cost. Nearly three times as many PV modules and batteries were required by the latter system than the one based on the total data set. In addition, the rectifier capacity was three times as large.

The results based on seasonal data represent over 26 kW in rated PV capacity, more than the maximum load demand noted. To allow for a design which required fewer PV modules and batteries, as well as reducing costs when optimizing with

Table 5.18-12. Constraints and Limits for Modified Edmonton Load 2 Optimization

Parameter	Value
Nominal Constraints	
$A_{w_{max}}$ (total)	60 m^2
(initial seasonal)	60 m^2
(final seasonal)	125 m^2
$A_{w_{min}}$	0 m^2
$N_{S_{max}}$ (total)	500
$N_{S_{max}}$ (seasonal)	1000
$N_{S_{min}}$ (total)	0
$N_{S_{min}}$ (seasonal)	0
$N_{B_{max}}$ (total)	500
$N_{B_{max}}$ (seasonal)	1000
$N_{B_{min}}$ (total)	0
$N_{B_{min}}$ (seasonal)	0
$P_{G_{max}}$ (initial)	5000 W
$P_{G_{max}}$ (final)	10000 W
$P_{G_{min}}$	250 W
Starting Points	
A_w (initial total)	45 m^2
(final total)	59 m^2
(initial seasonal)	58 m^2
(final seasonal)	120 m^2
N_S (initial total)	400
(final total)	250
(initial seasonal)	800
(final seasonal)	250
N_B (initial total)	400
(final total)	50
(initial seasonal)	800
(final seasonal)	50

Table 5.18-13. Comparison of Results for Edmonton Load 2 ($N_{S_{MIN}}$ = 0, $N_{B_{MIN}}$ = 0, 60 m^2 nominal WTG area)

Case								Results						
Load (kW)	$N_{S_{MIN}}$	$N_{B_{MIN}}$	C_W ($/m^2)	C_S ($/mod.)	C_B ($/A-hr/btty.)	C_F ($/L)	A_W (m^2)	N_S	N_B	P_G^* (W)	P_I (W)	P_B (W)	f (L/day)	Cost ($/yr)
							Total Data Set							
Mean	0	0	800	500	2.50	0.45	60.2	258	36	5000	4500	3500	2.58	28053
							Seasonal Data Set*							
Mean	0	0	800	500	2.50	0.45	60.2	750	98	5000	13500	2500	0.94	64277

*Seasonal fuel consumption average values

seasonal data, the upper constraint for the WTG area was raised from 60 m^2 to 125 m^2. The 125 m^2 area was chosen as it gave a similar number of PV modules and batteries. The results for the optimizations using these constraints are shown in Table 5.18-14.

The results based on each data set are generally similar except for the larger required WTG area for the seasonal data set results. In addition, the annual costs for each case are similar, indicating that the constraint on WTG's is the most important for this load, as changing the WTG area has a major effect on the results,

5.18.4.4. Simulations

Similar to what was done in 5.17., the performance of some of the systems using actual load and weather data was examined.

As an example of the system's behaviour, Figure 5.18-3 shows the results of one day's run based on the system design optimized for 100% load and full market prices given in Table 5.18-4. This case did not use PV modules. In order to complete this run, the battery charge rate for the lower half of the envelope was changed from *c*/10 to *c*/15 and the maximum auxiliary generator capacity was increased to 10 kW. Both the power required by the inverter and rectifier were within the limits of the selected components.

By comparison, Figure 5.18-4 shows the results for a run for the same day, but using the configuration based on the total data set and full market prices in Table 5.18-14 with the same modifications as those for the previous run. This case had a smaller WTG, 246 PV modules, and 39 batteries. An inverter capacity of over 7425 W was required, though the rectifier power was within the limits determined by the optimization algorithm.

Figure 5.18-5 shows the results for a different day and year, using the same system configuration as for Figure 5.18-4. The large increase in the output power from the WTG starting in the latter half of the day results in the batteries charging to a point that they must discharge in order to keep within the charge envelope. No adjustments to the auxiliary generator capacity or the lower charge rate were made, though the inverter capacity would have to be over 5800 W in order for this system to operate.

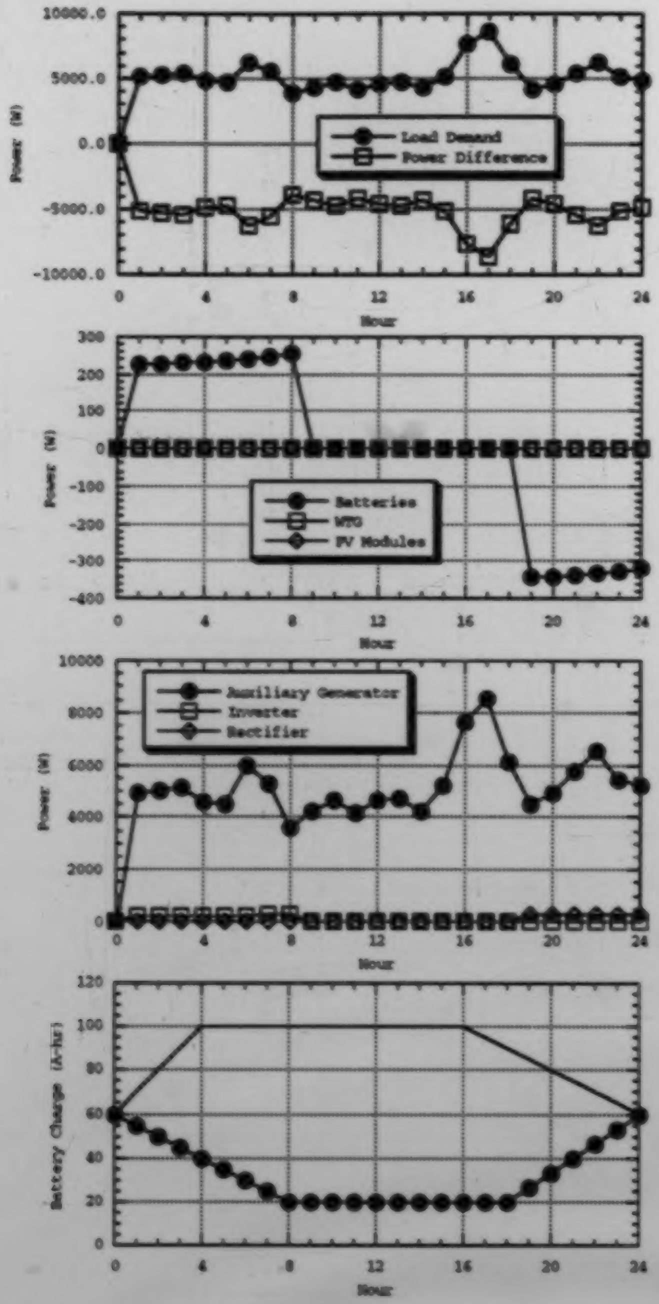
5.18.4.5. Capacity Revisions

As was noted in 5.17.5., the results from the simulations indicate that the capacities for the auxiliary generator,

Table 5.18-14. Revised Results for Edmonton Load 2 ($N_{S_{MIN}}$ = 0, $N_{B_{MIN}}$ = 0)

Case							Results							
Load (kW)	$N_{S_{MIN}}$	$N_{B_{MIN}}$	c_W (\$/m^2)	c_S (\$/mod.)	c_B (\$/A-hr/btty.)	c_F (\$/L)	A_W (m^2)	N_S	N_B	P_G^* (W)	P_I (W)	P_R (W)	f (L/day)	Cost (\$/yr)
							Total Data Set							
Mean	0	0	800	500	2.50	0.45	60.2	246	39	5500	4000	4000	2.24	27807
Mean	0	0	200	500	2.50	0.45	60.2	250	37	5500	4000	3500	2.91	23715
Mean	0	0	800	125	2.50	0.45	60.2	266	34	5000	4500	3500	2.58	16801
Mean	0	0	800	500	0.625	0.45	60.2	245	39	5500	4000	4000	2.26	24370
Mean	0	0	800	125	0.625	0.45	60.2	301	55	250	5000	250	0.03	12959
Mean	0	0	800	500	2.50	0.30	58.2	258	41	6000	4000	4000	2.55	28512
Mean	0	0	200	125	0.625	0.30	60.2	301	55	250	5000	250	0.03	8774
							Seasonal Data Set*							
Mean	0	0	800	500	2.50	0.45	124.6	214	35	5000	4000	3500	1.22	31777
Mean	0	0	200	500	2.50	0.45	123.6	224	35	5000	4000	3500	1.23	23666
Mean	0	0	800	125	2.50	0.45	125.7	227	32	4500	4000	3000	1.02	22201
Mean	0	0	800	500	0.625	0.45	125.7	206	35	5000	4000	3500	1.21	28380
Mean	0	0	800	125	0.625	0.45	123.6	277	47	1000	5000	2500	0.09	19486
Mean	0	0	800	500	2.50	0.30	125.7	210	34	5000	4000	3500	1.20	31413
Mean	0	0	200	125	0.625	0.30	124.6	263	43	2000	5000	2500	0.21	10812

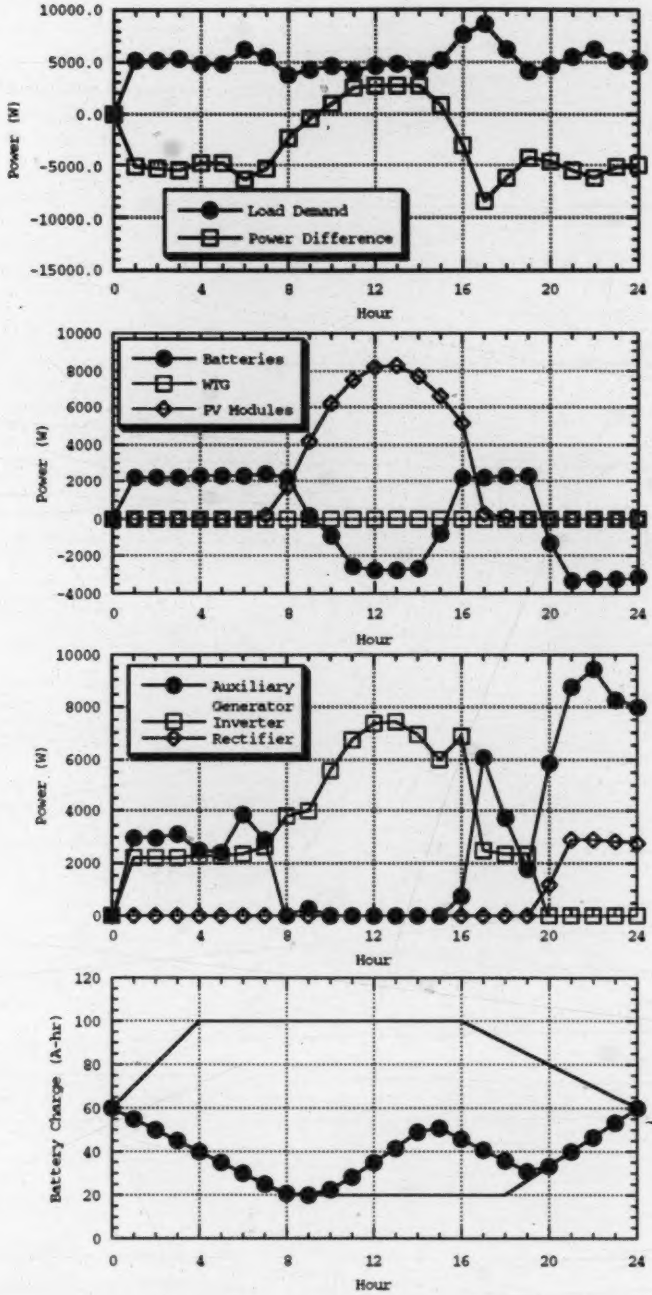
*Seasonal fuel consumption average values



A_a = 288.8 m^2 N_t = 0 N_b = 4

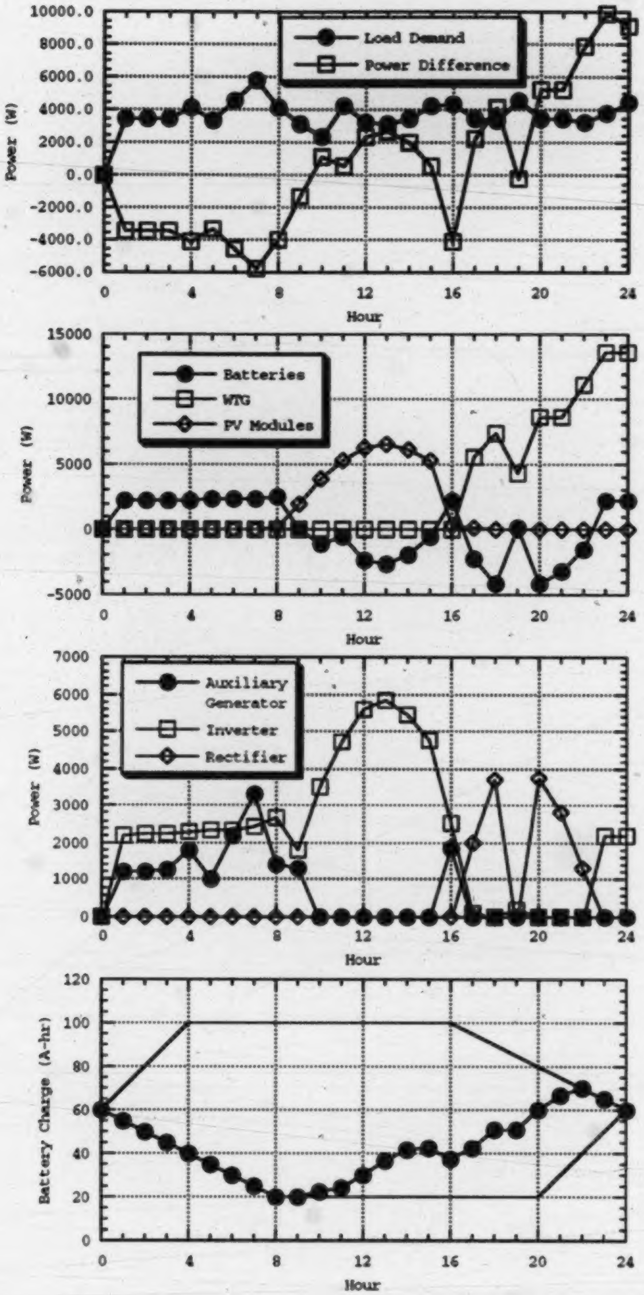
E_c^r = 10000 W P_r = 500 W P_i = 500 W

Figure 5.18-3. Run 1 for 1978, Day 57



A_v = 60.2 m^2 N_s = 246 N_p = 39
P_G^* = 10000 W P_I = 4000 W P_R = 4000 W

Figure 5.18-4. Run 2 for 1978, Day 57



A_w = 60.2 m^2 N_s = 246 N_B = 39

P_G^* = 5500 W P_I = 4000 W P_R = 4000 W

Figure 5.18-5. Run for 1995, Day 28

inverter, and rectifier as selected by the optimization algorithm were inadequate. The incremental capacities for these components used for this load were changed to 10 kW, with the results of these revisions given in Table 5.18-15.

Table 5.18-15 shows that the systems using the summer and winter data combined had the greatest proportional increases in cost (compared with those in Table 5.18-14), on the order of about 20%. By comparison, those results in Table 5.18-16 increased about 10%.

In addition, the installed cost for each system examined and the equivalent utility line length are given in Table 5.18-17, based on $20000/km [1]. In each table, the costs are about the same order of magnitude, though the lowest costs occur for those cases when the price of PV modules is reduced. The installed costs based on the total data set are a few percent less than those obtained with seasonal data, due largely to the smaller WTG areas in the former set. It should be noted that these costs are about 5 times greater than those given in Table 5.17-13.

Also, as had been done for the previous load, the annual cost of this utility line was calculated. The line costs are, in general, about 10% less than those for the renewable energy systems. Again, it is emphasized that those costs will be higher if the utility lines were longer.

For this load, an existing utility grid must be considerably further away from the load in question than would be the case for the load in 5.17. This implies that a renewable energy system for powering this load would only be competitive with a power utility if the load was located in a region well away from an urban centre.

5.18.5. Assessment

The systems given in Table 5.18-14 are feasible from an economic standpoint, but not always from a technical perspective. Based on the simulation results, some were better suited for service than others.

The results obtained for this load confirmed many of the findings for the previous one, namely that starting at a higher point results in a minimum, which produces a system which can potentially be used on an actual load. This system will not be solely reliant on a single renewable energy source but uses WTG's, PV modules, and batteries.

Having a large seasonal difference in the load results in different constraints being required, such as a larger WTG

Table 5.18-15. Revised Table 5.18-14 Results

Case							Results							
Load (kW)	$N_{S_{MIN}}$	$N_{B_{MIN}}$	C_W (\$/m^2)	C_S (\$/mod.)	C_B (\$/A-hr/btty.)	C_F (\$/L)	A_W (m^2)	N_S	N_B	P_G^* (W)	P_I (W)	P_R (W)	f (L/day)	Cost (\$/yr)
						Total Data Set								
Mean	0	0	800	500	2.50	0.45	60.2	246	39	10000	10000	10000	4.07	30641
Mean	0	0	200	500	2.50	0.45	60.2	250	37	10000	10000	10000	5.29	26728
Mean	0	0	800	125	2.50	0.45	60.2	266	34	10000	10000	10000	5.15	19915
Mean	0	0	800	500	0.625	0.45	60.2	245	39	10000	10000	10000	4.11	27208
Mean	0	0	800	125	0.625	0.45	60.2	301	55	10000	10000	10000	1.25	17192
Mean	0	0	800	500	2.50	0.30	58.2	258	41	10000	10000	10000	4.24	31076
Mean	0	0	200	125	0.625	0.30	60.2	301	55	10000	10000	10000	1.25	12918
						Seasonal Data Set*								
Mean	0	0	800	500	2.50	0.45	124.6	214	35	10000	10000	10000	2.45	33494
Mean	0	0	200	500	2.50	0.45	123.6	224	35	10000	10000	10000	2.47	25385
Mean	0	0	800	125	2.50	0.45	125.7	227	32	10000	10000	10000	2.27	23980
Mean	0	0	800	500	0.625	0.45	125.7	206	35	10000	10000	10000	2.43	30094
Mean	0	0	800	125	0.625	0.45	123.6	277	47	10000	10000	10000	0.85	21102
Mean	0	0	800	500	2.50	0.30	125.7	210	34	10000	10000	10000	2.40	33036
Mean	0	0	200	125	0.625	0.30	124.6	263	43	10000	10000	10000	1.05	12382

*Seasonal fuel consumption average values

Table 5.18-16. Edmonton Load 2 Installation Costs and Line Lengths

Case						Results							
Load (kW)	$N_{S_{MIN}}$	$N_{B_{MIN}}$	c_W (\$/m^2)	c_S (\$/mod.)	c_B (\$/A-hr/btty.)	A_W (m^2)	N_S	N_B	P_G^* (W)	P_I (W)	P_R (W)	Installed Cost (\$)	Length (km)
						Total Data Set							
Mean	0	0	800	500	2.50	60.2	246	39	10000	10000	10000	220946	11.0
Mean	0	0	200	500	2.50	60.2	250	37	10000	10000	10000	186299	9.3
Mean	0	0	800	125	2.50	60.2	266	34	10000	10000	10000	130196	6.5
Mean	0	0	800	500	0.625	60.2	245	39	10000	10000	10000	213321	10.7
Mean	0	0	800	125	0.625	60.2	301	55	10000	10000	10000	129321	6.5
Mean	0	0	800	500	2.50	58.2	258	41	10000	10000	10000	225784	11.3
Mean	0	0	200	125	0.625	60.2	301	55	10000	10000	10000	93112	4.7
						Seasonal Data Set							
Mean	0	0	800	500	2.50	124.6	214	35	10000	10000	10000	255464	12.8
Mean	0	0	200	500	2.50	123.6	224	35	10000	10000	10000	185471	9.3
Mean	0	0	800	125	2.50	125.7	227	32	10000	10000	10000	176920	8.8
Mean	0	0	800	500	0.625	125.7	206	35	10000	10000	10000	245732	12.3
Mean	0	0	800	125	0.625	123.6	277	47	10000	10000	10000	176446	8.8
Mean	0	0	800	500	2.50	125.7	210	34	10000	10000	10000	254045	12.7
Mean	0	0	200	125	0.625	124.6	263	43	10000	10000	10000	100491	5.0

Table 5.18-17. Edmonton Load 2 Power Line Costs

Case						Results								
Load (kW)	$N_{S_{MIN}}$	$N_{B_{MIN}}$	C_W (\$/m^2)	C_S (\$/mod.)	C_B (\$/A-hr/btty.)	A_W (m^2)	N_S	N_B	P_G^* (W)	P_I (W)	P_R (W)	Length (km)	Cost (\$/yr)
						Total Data Set							
Mean	0	0	800	500	2.50	60.2	246	39	10000	10000	10000	11.0	27682
Mean	0	0	200	500	2.50	60.2	250	37	10000	10000	10000	9.3	23793
Mean	0	0	800	125	2.50	60.2	266	34	10000	10000	10000	6.5	17203
Mean	0	0	800	500	0.625	60.2	245	39	10000	10000	10000	10.7	26967
Mean	0	0	800	125	0.625	60.2	301	55	10000	10000	10000	6.5	17100
Mean	0	0	800	500	2.50	58.2	258	41	10000	10000	10000	11.3	28431
Mean	0	0	200	125	0.625	60.2	301	55	10000	10000	10000	4.7	12847
						Seasonal Data Set*							
Mean	0	0	800	500	2.50	124.6	214	35	10000	10000	10000	12.8	31917
Mean	0	0	200	500	2.50	123.6	224	35	10000	10000	10000	9.3	23696
Mean	0	0	800	125	2.50	125.7	227	32	10000	10000	10000	8.8	22691
Mean	0	0	800	500	0.625	125.7	206	35	10000	10000	10000	12.3	30774
Mean	0	0	800	125	0.625	123.6	277	47	10000	10000	10000	8.8	22635
Mean	0	0	800	500	2.50	125.7	210	34	10000	10000	10000	12.7	31750
Mean	0	0	200	125	0.625	124.6	263	43	10000	10000	10000	5.0	13714

*Costs based on 74.8 kWh/day, 10% annual interest rate, and \$0.07/kWh [158] area when using seasonal data. This results in systems which are similar in cost, and use similar numbers of PV modules and batteries.

5.19. Lethbridge

5.19.1. Symbols

A_W = wind turbine generator rotor area (m^2)
$A_{W_{MAX}}$ = maximum wind turbine generator rotor area (m^2)
$A_{W_{MIN}}$ = minimum wind turbine generator rotor area (m^2)
c_B = battery cost (\$/A-hr/battery)
c_F = fuel cost (\$/L)
c_S = photovoltaic module cost (\$/module)
c_W = wind turbine cost (\$/m^2)
f = auxiliary generator fuel consumption rate (L/day)
N_B = number of batteries
$N_{B_{MAX}}$ = maximum number of batteries
$N_{B_{MIN}}$ = minimum number of batteries
N_S = number of photovoltaic modules
$N_{S_{MAX}}$ = maximum number of photovoltaic modules
$N_{S_{MIN}}$ = minimum number of photovoltaic modules
P_G^* = required auxiliary generator capacity (W)
$P_{G_{MAX}}$ = maximum auxiliary generator capacity (W)
$P_{G_{MIN}}$ = minimum auxiliary generator capacity (W)
P_I = inverter capacity (W)
P_R = rectifier capacity (W)

5.19.2. General

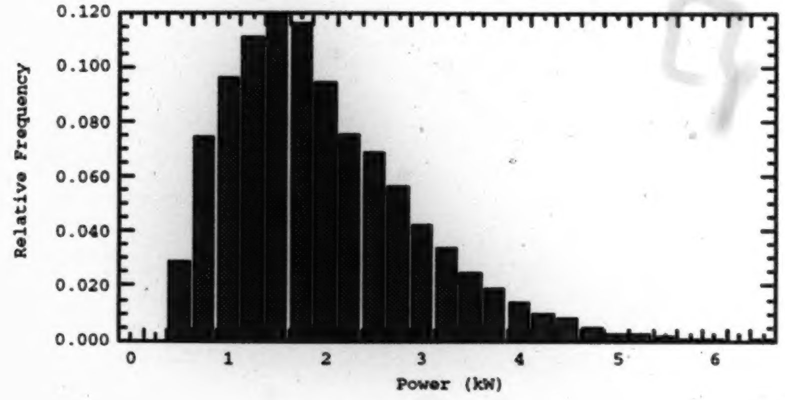
In order to further evaluate the optimization algorithm and test the findings made so far in the investigation, a different location and load were selected for examination

Data for a load at a southern Alberta location for the calendar year 1995 were obtained from TransAlta Utilities. In addition, weather data for the calendar years 1973 - 1993 were also obtained from Environment Canada, with the data for 1974 - 1993 used for calculating the means.

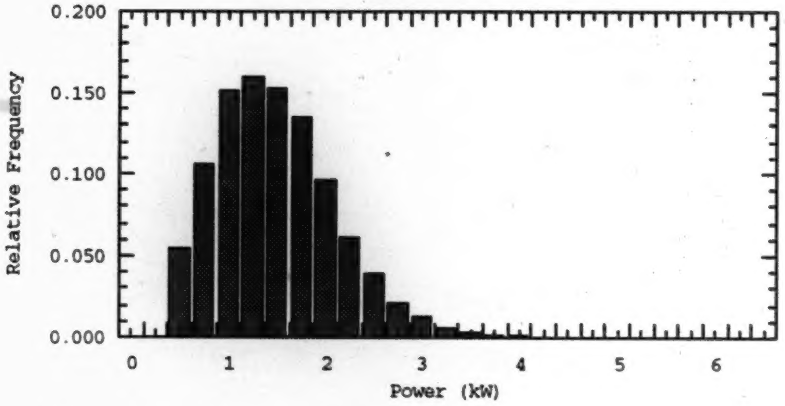
5.19.3. Load Description

Details concerning the nature of the load were not available. Because the time periods covered by the load data and weather data did not overlap, it was not possible to determine if there was a relationship between certain load demands and weather conditions at the time as had been done in 5.17. and 5.18.

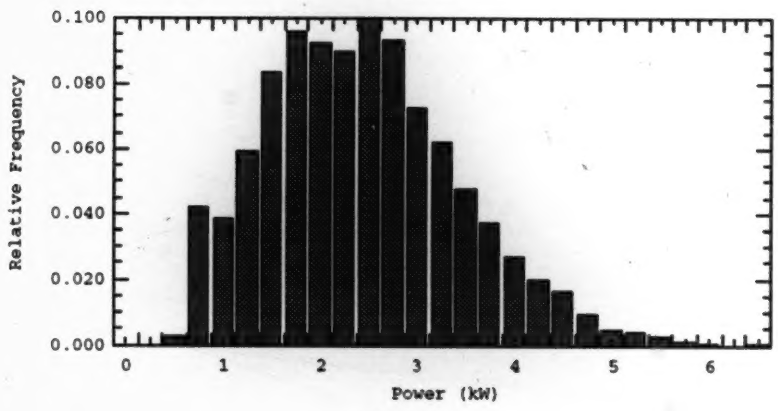
Histograms for the load data are shown in Figure 5.19-1. The



Total



Summer



Winter

Figure 5.19-1. Lethbridge Load Histograms

data range from zero to over 5 kW and display a distinctly seasonal behaviour.

5.19.4. Weather Data

5.19.4.1. Data Format

The weather data for Lethbridge provided by Environment Canada was of a different format than that for the Edmonton data used in 5.17. and 5.18. The meteorological elements used for this part of the investigation were extracted from the Lethbridge data set, converted into the format described in Appendix A, and then processed in the same manner as the data for Edmonton.

5.19.4.2. Wind Speeds

The histograms for the wind speeds are given in Figure 5.19-2. It should be noted that the range of velocities is higher for Lethbridge than for Edmonton. The data also indicate that the range of wind speeds is greater in winter than during the summer.

5.19.4.3. Wind Turbine Generator

The same two models of WTG were considered for this investigation, their parameters given in Table 5.12-1. An examination of their output powers throughout the time period covered by the weather indicated that the smaller-capacity WTG, the same one that had been used for the Edmonton loads, produced negligible amounts of power for about 40% of the entire time. By comparison, the larger-capacity WTG did so for about 50% of the time.

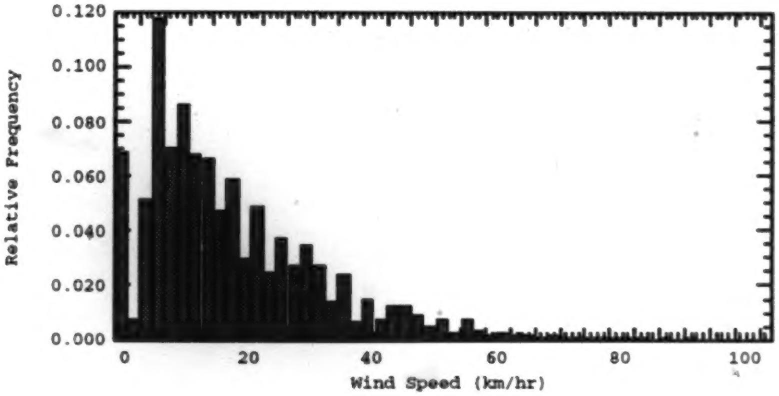
Based on that difference, the smaller-capacity WTG was selected for this part of the investigation.

5.19.5. Mean Values for Renewable Energy Sources and Loads

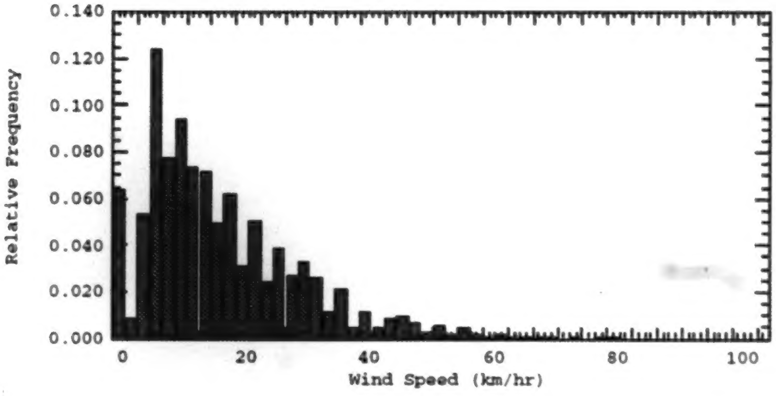
The hourly mean values for the WTG output power per unit area, PV module output power, and load demand are shown in Figure 5.19-3.

Of note is WTG power per unit area. In winter, it is significantly higher than for the summer. This is different than what was observed for Edmonton. In addition, the values are about three times greater than the corresponding value for Edmonton, indicating that a smaller number of WTG's can be used.

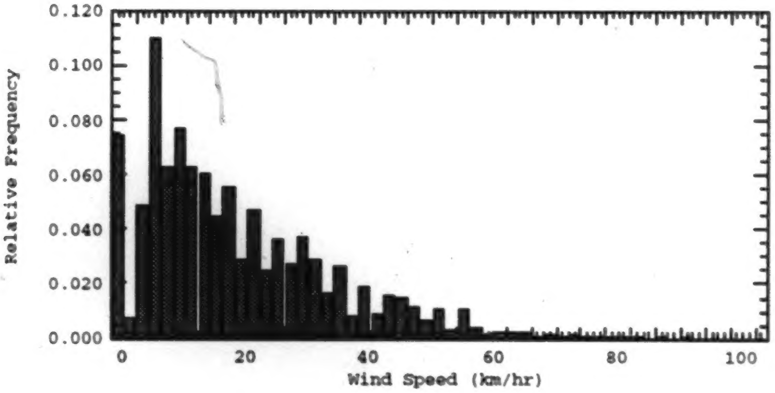
The hourly mean PV module output powers are comparable with



Total

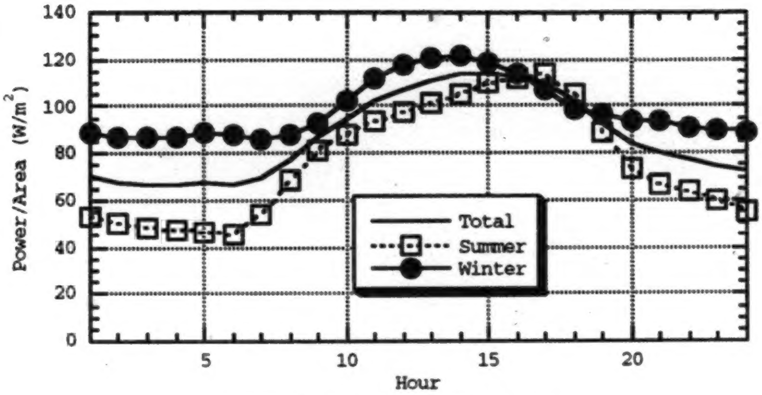


Summer

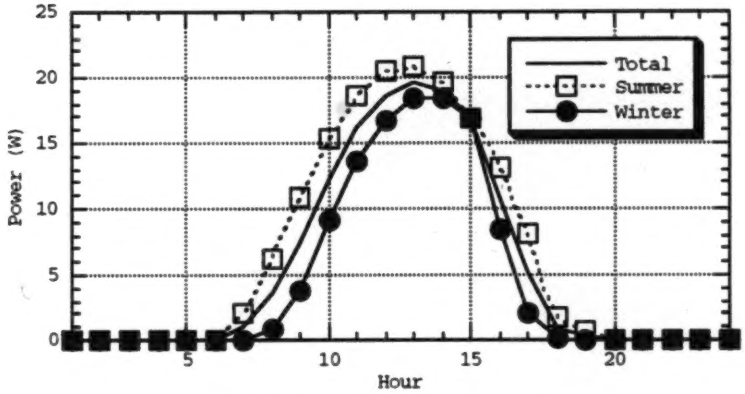


Winter

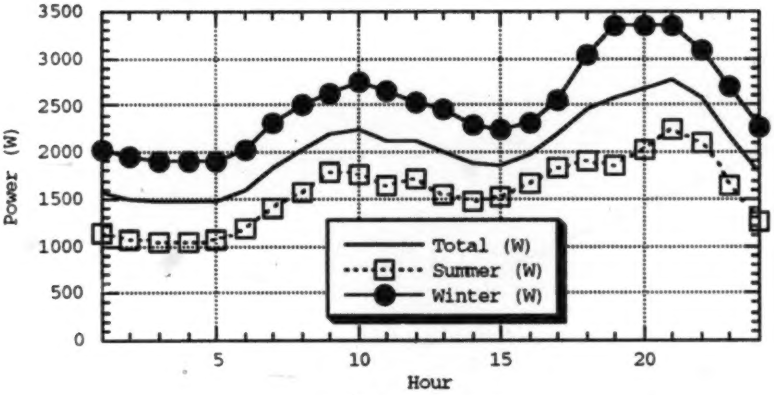
Figure 5.19-2. Lethbridge Wind Histograms



WTG Output Power/Area



PV Module Output Power



Load Demand

Figure 5.19-3. Lethbridge Mean Wind Turbine Generator Output Power/Area, Photovoltaic Module Output Power, and Load Demand

those for Edmonton.

The mean load demand, on the other hand, is higher than that for Edmonton Load 1, but lower than that for Edmonton Load 2.

5.19.6. Results

5.19.6.1. General

The initial optimizations based on maximum loads which were conducted in 5.17. and 5.18. for Edmonton Load 1 and Edmonton Load 2, respectively, resulted in systems which were based on WTG's. These maximum load demands have a low frequency of occurrence as do the wind velocities required by the WTG's to meet them. The result is WTG capacity which is not effectively used, being either idle for prolonged periods of time or, while operating, often producing large amounts of excess power above that required to meet the load demand, but which cannot be utilized due to battery charging constraints.

Systems which had better simulation results for Edmonton Load 1 and Edmonton Load 2 were based on results which used mean load values. For the purposes of this investigation, the remainder of this investigation will use these values for the load in question.

5.19.6.2. WTG Constraint

Based on Figure 5.19-3, an appropriate upper limit for the WTG area must be established. This constraint will, when used in an optimization, be utilized by the algorithm to determine the amount of PV module and battery capacity that will be required by a system.

An initial test using the parameters given in Table 5.19-1 indicated that, at full market prices and using total data the required WTG area was nearly 26 m^2 while constrained to a maximum of 30 m^2. The results are given in Table 5.19-2.

All subsequent runs were based on a maximum nominal required area of 22 m^2.

5.19.6.3. Results

Tests using the constraints given in Table 5.19-3 were conducted with the results given in Table 5.19-4.

Two characteristics about the Lethbridge load should be noted in interpreting the results. One is that the load demands for Lethbridge fall in between those for Edmonton Load 1 and Edmonton Load 2. The other is that more wind energy is

Table 5.19-1. Initial Parameters for Lethbridge

Parameter	Value
Constraints	
$A_{W_{MAX}}$	30 m^2
$A_{W_{MIN}}$	0 m^2
$N_{S_{MAX}}$	500
$N_{S_{MIN}}$	0
$N_{B_{MAX}}$	500
$N_{B_{MIN}}$	0
$P_{G_{MAX}}$	5000 W
$P_{G_{MIN}}$	250 W
Starting Point	
A_W	25 m^2
N_S	50
N_B	50

Table 5.19-2. Initial Optimization Results for Lethbridge ($N_{S_{MIN}}$ = 0, $N_{B_{MIN}}$ = 0, Total Data Set)

Case							Results							
Load (W)	$N_{S_{MIN}}$	$N_{B_{MIN}}$	C_W (\$/m^2)	C_S (\$/mod.)	C_B (\$/A-hr/btty.)	C_F (\$/L)	A_W (m^2)	N_S	N_B	$P_G^\bullet$ (W)	P_I (W)	P_R (W)	f (L/day)	Cost (\$/yr)
Mean	0	0	800	500	2.50	0.45	25.97	0	0	1000	0	0	1.00	3976

Table 5.19-3. Parameters for Lethbridge Runs

Parameter	Value
Nominal Constraints	
$A_{W_{MAX}}$	22 m^2
$A_{W_{MIN}}$	0 m^2
$N_{S_{MAX}}$ (total)	500
$N_{S_{MAX}}$ (seasonal)	500
$N_{S_{MIN}}$ (total)	0
$N_{S_{MIN}}$ (seasonal)	0
$N_{B_{MAX}}$ (total)	500
$N_{B_{MAX}}$ (seasonal)	500
$N_{B_{MIN}}$ (total)	0
$N_{B_{MIN}}$ (seasonal)	0
$P_{G_{MAX}}$	5000 W
$P_{G_{MIN}}$	250 W
Starting Points	
A_W	20 m^2
N_S (total)	50
N_S (seasonal)	100
N_B (total)	25
N_B (seasonal)	50

Table 5.19-4. Results for Lethbridge ($N_{S_{MIN}}$ = 0, $N_{B_{MIN}}$ = 0)

Case							Results							
Load (W)	$N_{S_{MIN}}$	$N_{B_{MIN}}$	C_W (\$/m^2)	C_S (\$/mod.)	C_B (\$/A-hr/btty.)	C_F (\$/L)	A_W (m^2)	N_S	N_B	P_G^* (W)	P_I (W)	P_R (W)	f (L/day)	Cost (\$/yr)
							Total Data Set							
Mean	0	0	800	500	2.50	0.45	20.77	30	4	1000	1000	500	1.34	5894
Mean	0	0	200	500	2.50	0.45	22.85	0	0	1000	0	0	1.75	2404
Mean	0	0	800	125	2.50	0.45	20.77	35	6	1000	1000	500	1.06	4713
Mean	0	0	800	500	0.625	0.45	20.77	29	5	1000	1000	500	1.33	5512
Mean	0	0	800	125	0.625	0.45	22.85	7	10	500	1000	1000	0.28	3753
Mean	0	0	800	500	2.50	0.30	20.77	29	5	1000	1000	500	1.33	5849
Mean	0	0	200	125	0.625	0.30	20.77	53	13	500	1000	500	0.28	2721
							Seasonal Data Set*							
Mean	0	0	800	500	2.50	0.45	22.85	47	4	1500	1000	500	1.57	7089
Mean	0	0	200	500	2.50	0.45	22.85	47	4	1500	1000	500	1.57	5503
Mean	0	0	800	125	2.50	0.45	22.85	1	0	1500	250	0	2.37	4359
Mean	0	0	800	500	0.625	0.45	22.85	40	35	4000	2000	3500	0.89	7953
Mean	0	0	800	125	0.625	0.45	22.85	50	6	1000	1000	1000	0.95	4670
Mean	0	0	800	500	2.50	0.30	22.85	47	4	1500	1000	500	1.57	6973
Mean	0	0	200	125	0.625	0.30	22.85	47	5	1000	1000	500	0.97	2913

*Seasonal fuel consumption average values

available at Lethbridge than Edmonton.

As a result of the greater availability of wind energy, each system described in Table 5.19-4 requires less WTG area than nearly all the systems for the two loads in the Edmonton area. This is reflected in the costs in Table 5.17-13 and the corresponding cases in Table 5.19-4 being, in general, lower.

Other differences can be seen when comparing the results in Tables 5.17-13 and 5.19-4.

One is that the Lethbridge results have, in general, a greater number of PV modules than Edmonton Load 1 for the results based on the respective total data sets. For the those based on seasonal data, Lethbridge requires about half the number as does Edmonton Load 1. Another difference is that Lethbridge requires far fewer batteries.

An explanation for this can be seen by comparing Figures 5.17-1 and 5.19-2, especially the mean WTG output power per unit area. A WTG at Lethbridge can produce about 2 - 3 times as much power than would one at Edmonton, particularly during the winter. The simulation results for Edmonton Load 1 and Edmonton Load 2 showed that battery power is required during the early morning. The greater availability of WTG power at Lethbridge would reduce the necessity for batteries during that same time.

During the middle of the day, the mean hourly load demand at Lethbridge (based on the total data set) is about 1.5 times that for Edmonton Load 1. Because the WTG area was less at Lethbridge, and fewer batteries were available, more PV modules would be required to meet the load demand.

When seasonal effects are considered, the mean mid-day load demand at Lethbridge is about 2.5 time greater than for Edmonton. At the same time, the mean WTG output power per unit area is about twice that for Edmonton during the summer and about three times greater during the winter. This would reduce the requirement for PV modules during the winter when less sunlight is available.

When only the price of WTG's are reduced and the total data set is used, Table 5.19-4 shows that a renewable energy system based solely on wind power is possible. Something similar also occurs when only the PV module price is reduced, but seasonal data are used, though one PV module is required.

In general, the costs for Lethbridge are lower than for Edmonton Load 1, even though the load demand is higher and less WTG are is required. This can be attributed to the greater WTG output power per unit area at Lethbridge.

5.19.6.4. Simulations

As had been done for Edmonton Load 1 and Edmonton Load 2, in 5.17. and 5.18., respectively, some of the results were tested in a simulation. All 21 years of the weather data were used and since only one year's worth of load data were available and were read sequentially into an array 21 times to provide continuity.

Two different configurations from Table 5.19-4 were selected and simulated for Day 284, 1984 as examples of the system's performance. Figures 5.19-4 and 5.19-5 show results for Day 1 of 1974, The system for Figure 5.19-4 is based on results determined from the total data set at full market prices as indicated. The other system was determined from the seasonal data for prices which were fully reduced as shown.

For both cases, the required auxiliary generator capacity was raised to 5 kW. The rectifier capacity for the first case would have to be over 885 W for it to operate, while the one for the second case would have to be over 504 W in order for the system to properly operate.

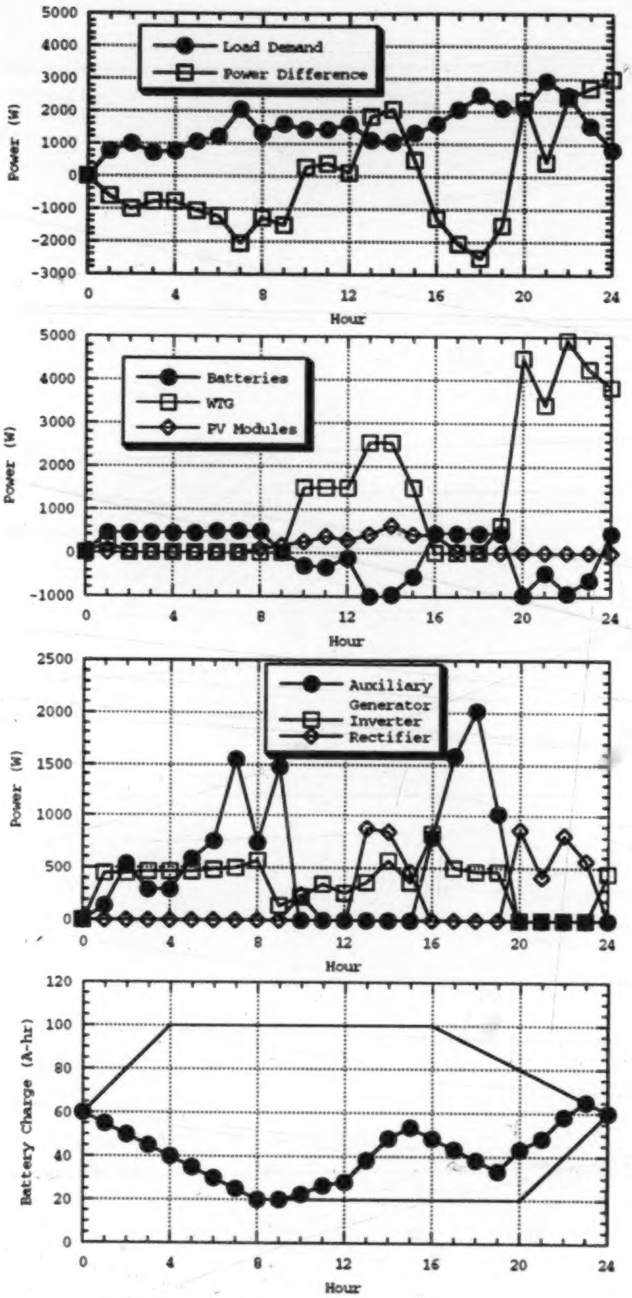
5.19.6.5. Capacity Revisions

Based on Figures 5.19-4 and 5.19-5, the incremental capacities of the auxiliary generator, inverter, and rectifier were increased from 500 W to 5000 W. The costs based on these revisions are presented in Table 5.19-5.

Comparing Tables 5.19-4 and 5.19-5, the costs based on the total data set increased on the order from about 50% to about 100%. The increases in costs based on seasonal data were considerably smaller.

Based on Table 5.19-5, the installed cost for each case are given in Tables 5.19-6 distances for new power utility line, based on $20000/km. The case, based on the total data set, for which the WTG price was reduced had a significantly lower installed cost than the remainder of those examined.

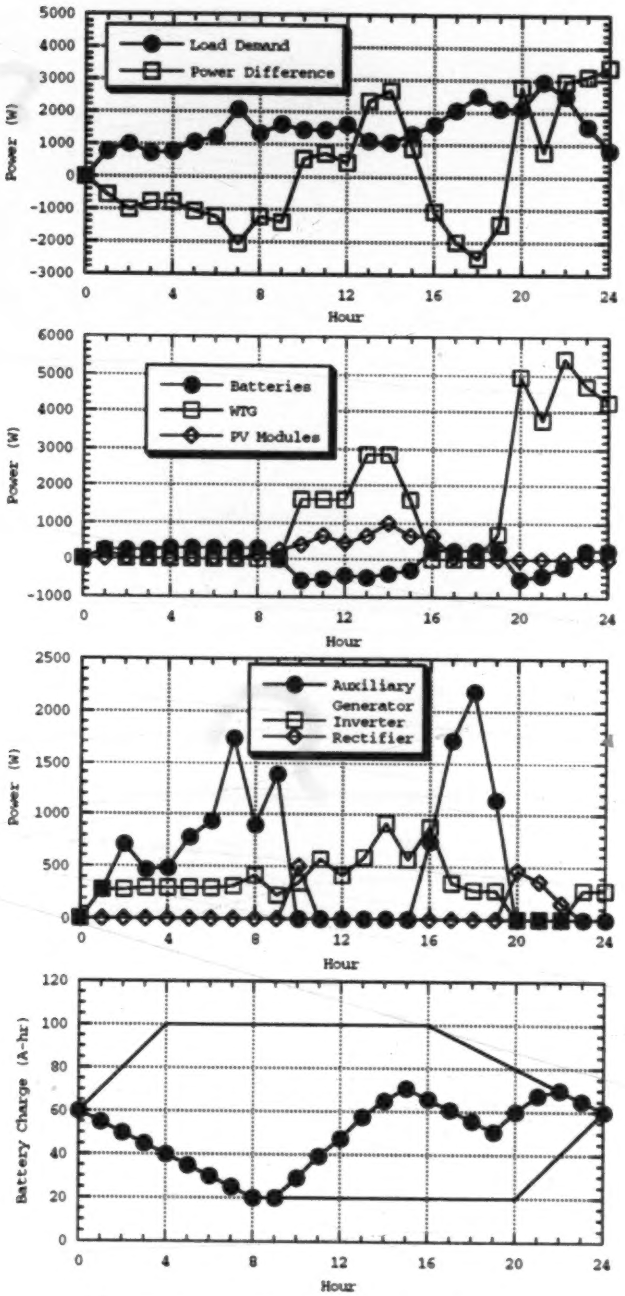
Table 5.19-7 shows the equivalent annual cost for these lines, based on 48.6 kWh/day. When compared with the results in Table 5.17-17 for Edmonton Load 1, the costs for Lethbridge are, in general lower, even though the load demand is significantly greater. Again, this can be attributed to the more wind energy being available than at Edmonton.



A_w = 20.77 m^2 N_s = 30 N_b = 4

P_c^* = 5000 W P_I = 1000 W P_R = 500 W

Figure 5.19-4. Run 1 for 1984, Day 284



A_w = 22.85 m^2 N_s = 47 N_B = 5
P_G^* = 5000 W P_I = 1000 W P_R = 500 W

Figure 5.19-5. Run 2 for 1984, Day 284

Table 5.19-5. Revised Table 5.19-4 Results

Case							Results							
Load (W)	$N_{S_{MIN}}$	$N_{B_{MIN}}$	C_W (\$/m^2)	C_S (\$/mod.)	C_B (\$/A-hr/btty.)	C_F (\$/L)	A_W (m^2)	N_S	N_B	P_G^* (W)	P_I (W)	P_R (W)	f (L/day)	Cost (\$/yr)
							Total Data Set							
Mean	0	0	800	500	2.50	0.45	20.77	30	4	5000	5000	5000	6.73	10381
Mean	0	0	200	500	2.50	0.45	22.85	0	0	5000	0	0	8.73	6723
Mean	0	0	800	125	2.50	0.45	20.77	35	6	5000	5000	5000	5.28	8480
Mean	0	0	800	500	0.625	0.45	20.77	29	5	5000	5000	5000	6.64	9983
Mean	0	0	800	125	0.625	0.45	22.85	7	10	5000	5000	5000	2.84	6806
Mean	0	0	800	500	2.50	0.30	20.77	29	5	5000	5000	5000	6.64	9928
Mean	0	0	200	125	0.625	0.30	20.77	53	13	5000	5000	5000	2.84	5644
							Seasonal Data Set*							
Mean	0	0	800	500	2.50	0.45	22.85	47	4	5000	5000	5000	5.25	8884
Mean	0	0	200	500	2.50	0.45	22.85	47	4	5000	5000	5000	5.25	7297
Mean	0	0	800	125	2.50	0.45	22.85	1	0	5000	5000	0	7.90	6129
Mean	0	0	800	500	0.625	0.45	22.85	40	35	5000	5000	5000	1.11	8523
Mean	0	0	800	125	0.625	0.45	22.85	50	6	5000	5000	5000	4.77	6439
Mean	0	0	800	500	2.50	0.30	22.85	47	4	5000	5000	5000	5.25	8498
Mean	0	0	200	125	0.625	0.30	22.85	47	5	5000	5000	5000	4.85	4467

*Seasonal fuel consumption average values

Table 5.19-6. Lethbridge Installation Costs and Line Lengths

Case						Results							
Load (W)	$N_{S_{MIN}}$	$N_{B_{MIN}}$	C_W (\$/m^2)	C_S (\$/mod.)	C_B (\$/A-hr/btty.)	A_W (m^2)	N_S	N_B	$P_G^\bullet$ (W)	P_I (W)	P_R (W)	Installed Cost (\$)	Length (km)
						Total Data Set							
Mean	0	0	800	500	2.50	20.77	30	4	5000	5000	5000	52619	2.6
Mean	0	0	200	500	2.50	22.85	0	0	5000	0	0	14570	0.7
Mean	0	0	800	125	2.50	20.77	35	6	5000	5000	5000	42494	2.1
Mean	0	0	800	500	0.625	20.77	29	5	5000	5000	5000	51432	2.6
Mean	0	0	800	125	0.625	22.85	7	10	5000	5000	5000	39781	2.0
Mean	0	0	800	500	2.50	20.77	29	5	5000	5000	5000	52369	2.6
Mean	0	0	200	125	0.625	20.77	53	13	5000	5000	5000	31592	1.6
						Seasonal Data Set							
Mean	0	0	800	500	2.50	22.85	47	4	5000	5000	5000	62781	3.1
Mean	0	0	200	500	2.50	22.85	47	4	5000	5000	5000	49070	2.5
Mean	0	0	800	125	2.50	22.85	1	0	5000	5000	0	38406	1.9
Mean	0	0	800	500	0.625	22.85	40	35	5000	5000	5000	60468	3.0
Mean	0	0	800	125	0.625	22.85	50	6	5000	5000	5000	44906	2.2
Mean	0	0	800	500	2.50	22.85	47	4	5000	5000	5000	62781	3.1
Mean	0	0	200	125	0.625	22.85	47	5	5000	5000	5000	30758	1.5

Table 5,19-7. Lethbridge Power Line Costs

Case						Results							
Load (W)	$N_{S_{MIN}}$	$N_{B_{MIN}}$	C_W ($/m^2)	C_S ($/mod.)	C_B ($/A-hr/btty.)	A_W (m^2)	N_S	N_B	$P_G^{\bullet}$ (W)	P_I (W)	P_R (W)	Length (km)	Cost ($/yr)
					Total Data Set								
Mean	0	0	800	500	2.50	20.77	30	4	5000	5000	5000	2.6	7423
Mean	0	0	200	500	2.50	22.85	0	0	5000	0	0	0.7	2954
Mean	0	0	800	125	2.50	20.77	35	6	5000	5000	5000	2.1	6234
Mean	0	0	800	500	0.625	20.77	29	5	5000	5000	5000	2.6	7284
Mean	0	0	800	125	0.625	22.85	7	10	5000	5000	5000	2.0	5915
Mean	0	0	800	500	2.50	20.77	29	5	5000	5000	5000	2.6	7394
Mean	0	0	200	125	0.625	20.77	53	13	5000	5000	5000	1.6	4953
					Seasonal Data Set*								
Mean	0	0	800	500	2.50	22.85	47	4	5000	5000	5000	3.1	8617
Mean	0	0	200	500	2.50	22.85	47	4	5000	5000	5000	2.5	7006
Mean	0	0	800	125	2.50	22.85	1	0	5000	5000	0	1.9	5754
Mean	0	0	800	500	0.625	22.85	40	35	5000	5000	5000	3.0	8345
Mean	0	0	800	125	0.625	22.85	50	6	5000	5000	5000	2.2	6517
Mean	0	0	800	500	2.50	22.85	47	4	5000	5000	5000	3.1	8617
Mean	0	0	200	125	0.625	22.85	47	5	5000	5000	5000	1.5	4855

Costs based on 48.6 kWh/day, 10% annual interest rate, and $0.07/kWh [158]

When the results based on seasonal data are considered, the annual costs for a renewable energy system (Table 5.19-6) are similar to those for the utility line (Table 5.19-7) are comparable, indicating that a renewable energy system may be an economical alternative at Lethbridge.

5.19.7. Assessment

The results for Lethbridge show that a different location and the associated weather conditions are significant factors in optimizing a hybrid renewable energy system. The greater availability of energy from the wind, plus a significant increase in it during the winter, led to a set of systems requiring less capacity than was needed for 5.17., but serving a larger load.

The results also confirmed the use of a higher starting point for a run tends to result designs that make use of WTG's, PV modules, and batteries, as was noted in 5.17.6. and 5.18.4.

5.20. Victoria

5.20.1. Symbols

A_W = wind turbine generator rotor area (m^2)
$A_{W_{MAX}}$ = maximum wind turbine generator rotor area (m^2)
$A_{W_{MIN}}$ = minimum wind turbine generator rotor area (m^2)
c_B = battery cost ($/A-hr/battery)
c_F = fuel cost ($/L)
c_S = photovoltaic module cost ($/module)
c_W = wind turbine cost ($/m^2)
f = auxiliary generator fuel consumption rate (L/day)
N_B = number of batteries
$N_{B_{MAX}}$ = maximum number of batteries
$N_{B_{MIN}}$ = minimum number of batteries
N_S = number of photovoltaic modules
$N_{S_{MAX}}$ = maximum number of photovoltaic modules
$N_{S_{MIN}}$ = minimum number of photovoltaic modules
P_G^* = required auxiliary generator capacity (W)
$P_{G_{MAX}}$ = maximum auxiliary generator capacity (W)
$P_{G_{MIN}}$ = minimum auxiliary generator capacity (W)
P_I = inverter capacity (W)
P_R = rectifier capacity (W)

5.20.2. General

The loads examined so far were from two locations in Alberta which were sufficiently distant from one another that significant differences in the weather conditions were observed in the data. In order to further evaluate the optimization algorithm, a load in a different climate and geographical environment than Alberta was considered for examination.

Data for a load in the vicinity of Victoria, B. C. were obtained from B. C. Hydro for the fiscal period from April 1996 to March 1999. As was the case with the Lethbridge load, weather data for the calendar years from 1973 - 1993 were obtained from Environment Canada.

5.20.3. Load Description

The load for Victoria was identified as being for a horticultural application [160].

Histograms for the load are given in Figure 5.20-1. The data range from zero to about 36 kW in the summer, which is about three times as large as Edmonton Load 2. This load displays a distinctly seasonal behaviour, since the histograms for the summer and winter data are significantly different.

The software used for processing the load data required sequential data based on calendar years. In order to accommodate this, the data for 1999 (January 1 to March 31) was placed in the sequence before the data starting at April 1996.

5.20.4. Weather Data

5.20.4.1. Data Format

The Victoria weather data was processed as mentioned in 5.19.4.1.

5.20.4.2. Wind Speeds

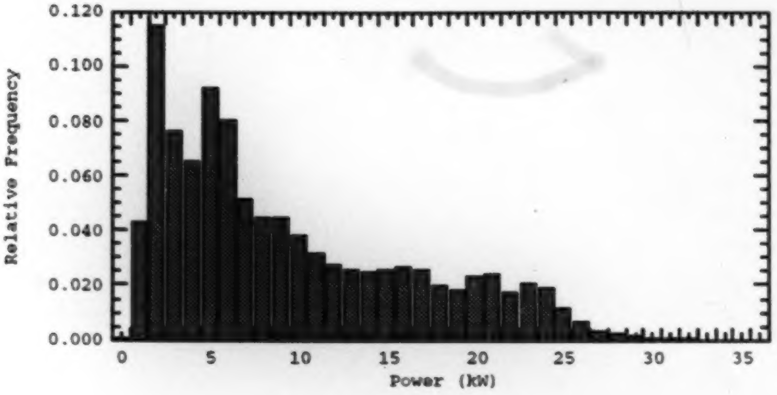
The histograms for the wind speeds are given in Figure 5.20-2. The range of wind speeds is slightly smaller than that for Edmonton with a maximum of about 60 km/hr. The data indicate that the range of wind velocities is greater in winter than in summer.

5.20.4.3. Wind Turbine Generator

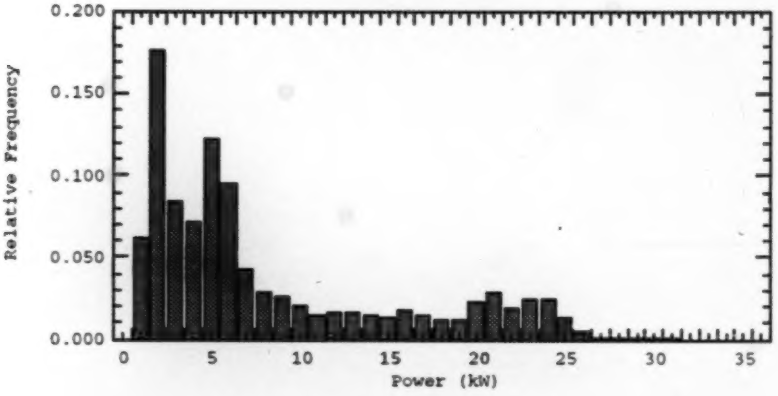
The WTG model used for Edmonton Load 1, Edmonton Load 2, and Lethbridge was also used in this part of the investigation.

5.20.5. Mean Values for Renewable Energy Sources and Loads

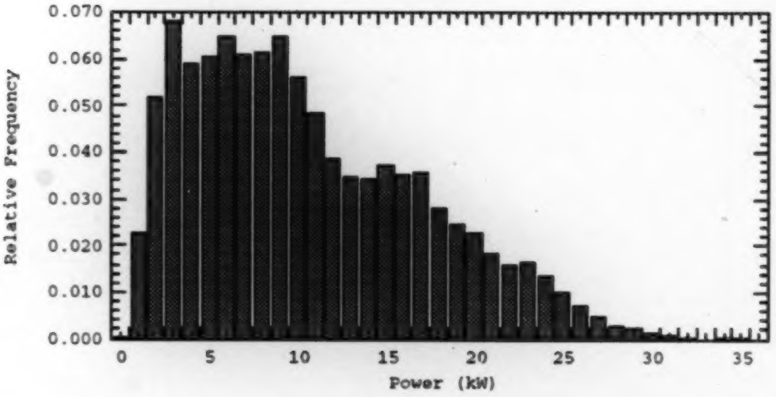
The hourly mean values for the WTG output power per unit area, PV module output power, and load demand are shown in Figure 5.20-3.



Total

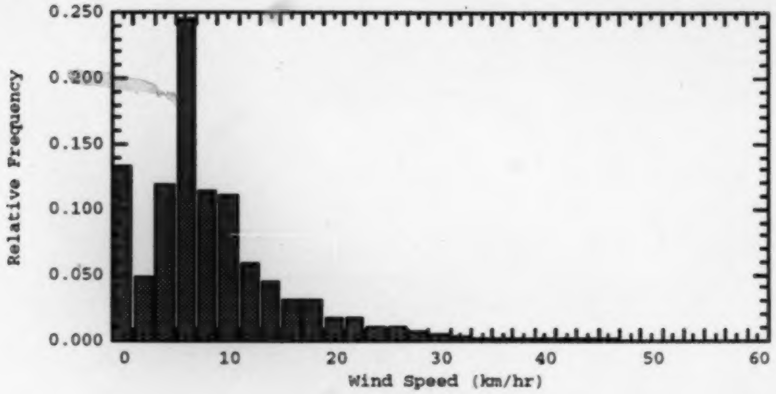


Summer

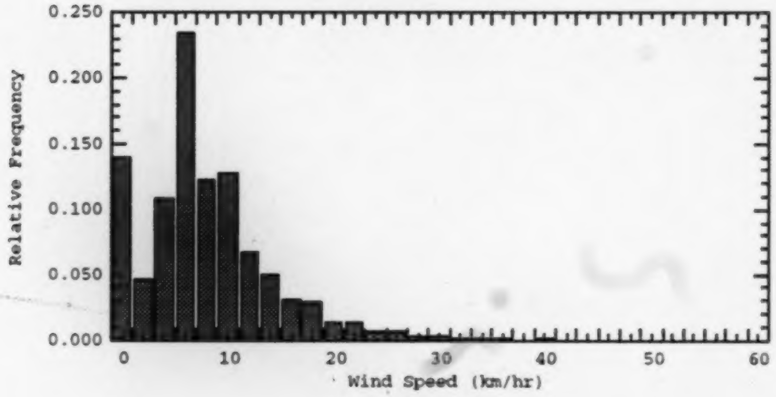


Winter

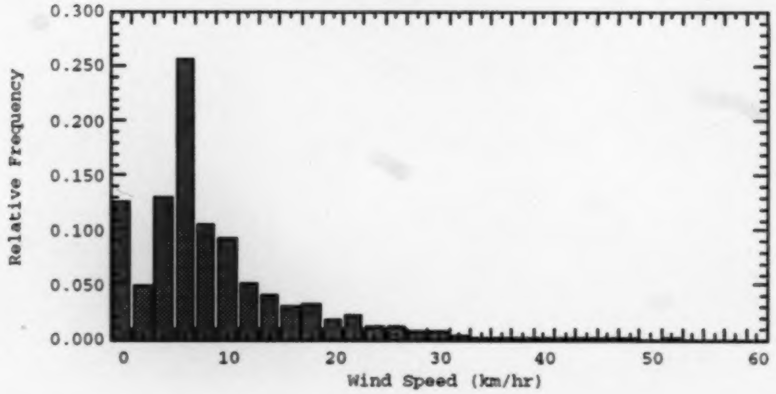
Figure 5.20-1. Victoria Load Histograms



Total

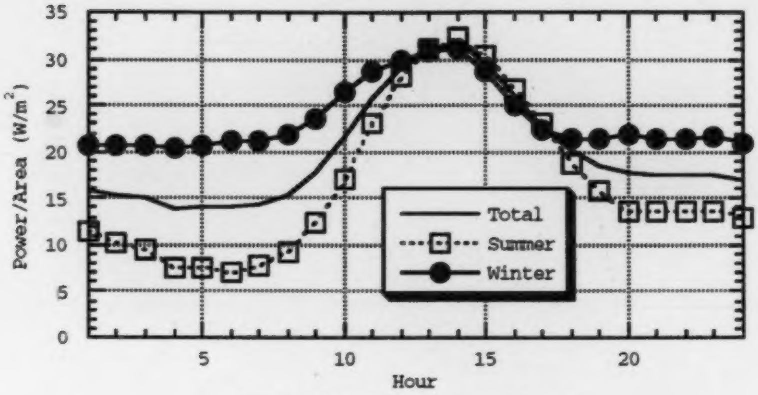


Summer

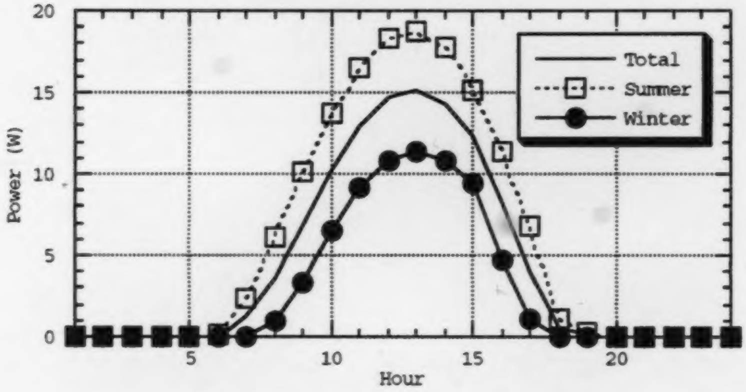


Winter

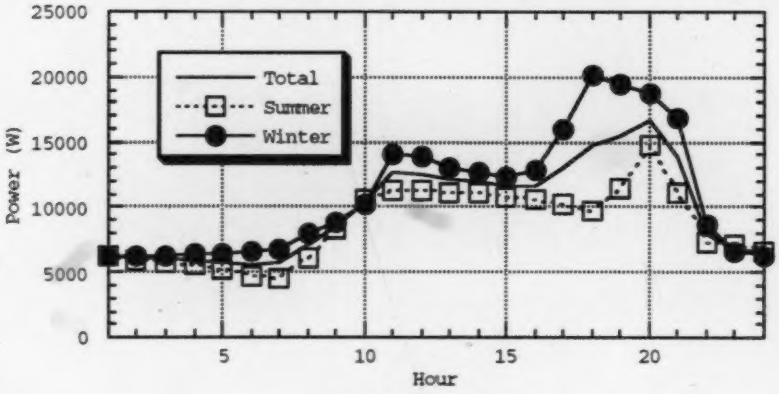
Figure 5.20-2. Victoria Wind Histograms



WTG Output Power/Area



PV Module Output Power



Load Demand

Figure 5.20-3. Victoria Mean Wind Turbine Generator Output Power/Area, Photovoltaic Module Output Power, and Load Demand

As had been the case for Lethbridge, the mean hourly WTG output power per unit area was generally greater during the winter than the summer. The seasonal difference is most apparent at about 0600 hours.

The hourly mean values for the PV module output power are comparable with what had been observed at Edmonton and Lethbridge.

The mean holy load demand displays two peaks: the smaller occurring late in the morning and the larger at mid-evening. The time at which the larger peak occurs is later for the summer than for the winter.

5.20.6. Results

5.20.6.1. General

The optimizations for this load were conducted in the same manner as those for Lethbridge.

5.20.6.2. WTG Constraint

An initial test using the parameters given in Table 5.20-1 indicated that, at full market prices, the required WTG area, with no PV modules or batteries present, was over 480 m^2, while constrained to a maximum of 1000 m^2. The results are given in Table 5.20-2.

These parameters were used due to the magnitudes of the loads involved.

In order to constrain the optimization algorithm so that any results would require PV modules and batteries, the maximum required WTG area was constrained to 435 m^2.

5.20.6.3. Results

The optimization algorithm was set to the parameters shown in Table 5.20-3 with the results given in Table 5.20-4.

The systems based on the total data set are similar in design and cost to their respective counterparts based on seasonal data. The main difference between those sets of results is the number of batteries required, which affects the capacities of the auxiliary generator, inverter, and rectifier.

One possible explanation can be seen by comparing the seasonal histograms for this load with the ones for Edmonton Load 2. The seasonal histograms for Edmonton Load 2 were distinctly different, with the respective modes having relative frequencies

Table 5.20-1. Initial Parameters for Victoria

Parameter	Value
Nominal Constraints	
$A_{W_{MAX}}$	1000 m^2
$A_{W_{MIN}}$	0 m^2
$N_{S_{MAX}}$	1000
$N_{S_{MIN}}$	0
$N_{B_{MAX}}$	1000
$N_{B_{MIN}}$	0
$P_{G_{MAX}}$	15000 W
$P_{G_{MIN}}$	250 W
Starting Point	
A_W	500 m^2
N_S	0
N_B	0

Table 5.20-2. Initial Optimization Results for Victoria (Seasonal Data Set)

Case							Results							
Load (kW)	$N_{S_{MIN}}$	$N_{B_{MIN}}$	c_W (\$/m^2)	c_S (\$/mod.)	c_B (\$/A-hr/btty.)	c_F (\$/L)	A_W (m^2)	N_S	N_B	P_G^* (W)	P_I (W)	P_R (W)	f (L/day)	Cost (\$/yr)
Mean	0	0	800	500	2.50	0.45	480.9	0	0	11000	0	0	49.20	67765

Table 5.20-3. Parameters for Victoria

Parameter	Value
Nominal Constraints	
$A_{W_{MAX}}$	435 m^2
$A_{W_{MIN}}$	0 m^2
$N_{S_{MAX}}$	500
$N_{S_{MIN}}$	0
$N_{B_{MAX}}$	500
$N_{B_{MIN}}$	0
$P_{G_{MAX}}$	15000 W
$P_{G_{MIN}}$	250 W
Starting Point	
A_W	420 m^2
N_S	400
N_B	100

Table 5.20-4. Results for Victoria ($N_{S_{MIN}} = 0$, $N_{B_{MIN}} = 0$)

Case							Results							
Load (W)	$N_{S_{MIN}}$	$N_{B_{MIN}}$	c_W (\$/m^2)	c_S (\$/mod.)	c_B (\$/A-hr/btty.)	c_F (\$/L)	A_W (m^2)	N_S	N_B	P_G^* (W)	P_I (W)	P_R (W)	f (L/day)	Cost (\$/yr)
							Total Data Set							
Mean	0	0	800	500	2.50	0.45	431.1	349	16	9500	5000	2000	25.24	75820
Mean	0	0	200	500	2.50	0.45	435.2	326	16	9500	4500	2000	25.04	44583
Mean	0	0	800	125	2.50	0.45	435.2	330	14	9500	4500	1500	25.26	60473
Mean	0	0	800	500	0.625	0.45	431.1	321	60	7000	4500	6000	14.75	70977
Mean	0	0	800	125	0.625	0.45	425.9	462	103	4500	6500	4000	6.18	56709
Mean	0	0	800	500	2.50	0.30	420.7	403	19	9500	5500	2000	25.37	76481
Mean	0	0	200	125	0.625	0.30	435.2	409	97	5000	6000	4000	7.74	26434
							Seasonal Data Set*							
Mean	0	0	800	500	2.50	0.45	435.2	384	53	9000	6500	5000	17.72	80055
Mean	0	0	200	500	2.50	0.45	429.0	398	54	9000	7000	5500	17.85	50745
Mean	0	0	800	125	2.50	0.45	430.0	388	55	9000	7000	5500	17.74	63280
Mean	0	0	800	500	0.625	0.45	427.9	377	72	8000	6500	5500	14.26	73832
Mean	0	0	800	125	0.625	0.45	434.2	430	100	6500	7500	2000	8.17	57410
Mean	0	0	800	500	2.50	0.30	426.9	397	55	9000	7000	5500	17.85	79060
Mean	0	0	200	125	0.625	0.30	421.7	423	80	8000	7500	4500	13.41	27174

*Seasonal fuel consumption average values

of the same order of magnitude. The load for Victoria also shows seasonal differences, but the mode is not as distinctly defined.

The magnitudes of the mean load demands for Victoria are much larger than those for Edmonton Load 2. This is reflected in the costs when two sets of results in Tables 5.18-14 and 5.20-4 are compared. It can be seen that the costs for the Victoria load are also greater than those for Edmonton Load 2 to the same degree.

5.20.7. Assessment

The magnitudes of this load are about 10 times greater than those for Edmonton Load 1. The results show that the optimization algorithm can be applied to loads of about this size. Another aspect to this part of the investigation was that this load was located at a coastal location which had a different climate than Edmonton and Lethbridge.

5.21. Delta

5.21.1. Symbols

A_W = wind turbine generator rotor area (m^2)
$A_{W_{MAX}}$ = maximum wind turbine generator rotor area (m^2)
$A_{W_{MIN}}$ = minimum wind turbine generator rotor area (m^2)
c_B = battery cost ($/A-hr/battery)
c_F = fuel cost ($/L)
c_S = photovoltaic module cost ($/module)
c_W = wind turbine cost ($/m^2)
f = auxiliary generator fuel consumption rate (L/day)
N_B = number of batteries
$N_{B_{MAX}}$ = maximum number of batteries
$N_{B_{MIN}}$ = minimum number of batteries
N_S = number of photovoltaic modules
$N_{S_{MAX}}$ = maximum number of photovoltaic modules
$N_{S_{MIN}}$ = minimum number of photovoltaic modules
P_G^* = required auxiliary generator capacity (W)
$P_{G_{MAX}}$ = maximum auxiliary generator capacity (W)
$P_{G_{MIN}}$ = minimum auxiliary generator capacity (W)
P_I = inverter capacity (W)
P_R = rectifier capacity (W)

5.21.2. General

Data for a load in the Delta, B. C. region located at Delta were obtained from B. C. Hydro for the fiscal period from April 1996 to March 1999. In addition, weather data for the calendar years from 1973 - 1993 were obtained from Environment

Canada.

The magnitudes of the hourly load demands are considerably greater than those any of those previously examined. In this section, aspects of optimizing such a large load will be considered.

5.21.3. Load Description

The load for the Delta area was identified as being for a horticultural application [161].

Histograms for the load are given in Figure 5.21-1. The data range from zero to more than 2.0 MW. This load displays a distinctly seasonal behaviour, since the histograms for the summer and winter data are significantly different.

The sequence of the actual load demand data was revised as given in 5.20.3.

5.21.4. Weather Data

5.21.4.1. Data Format

The Delta weather data was processed as mentioned in 5.19.4.1.

5.21.4.2. Wind Speeds

The histograms for the wind speeds are given in Figure 5.21-2. The range of wind speeds is greater than that for Edmonton with a maximum of over 70 km/hr, but smaller than that for Lethbridge. The data also show that the range of velocities is greater in summer than in winter.

5.21.4.3. Wind Turbine Generator

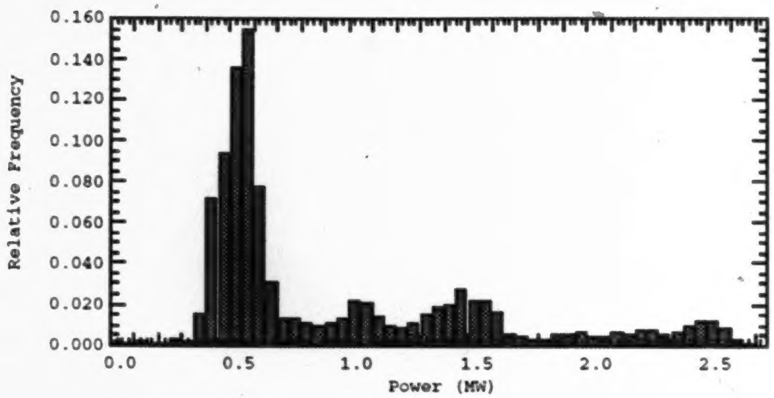
The WTG model used for the previous loads was also used in this part of the investigation.

5.21.5. Mean Values for Renewable Energy Sources and Loads

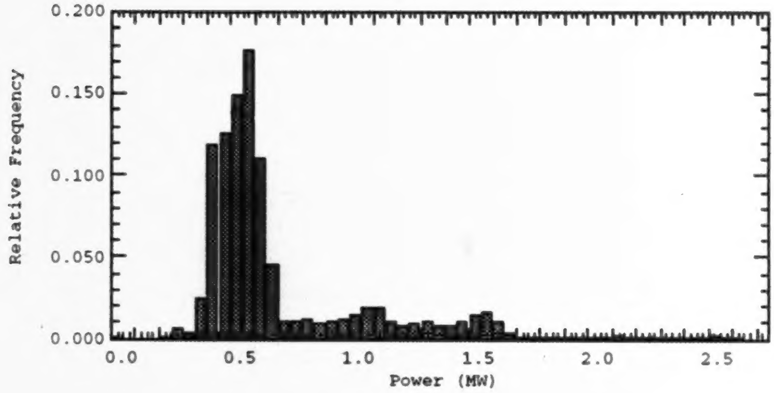
The hourly mean values for the WTG output power per unit area, PV module output power, and load demand are shown in Figure 5.21-3.

As had been the case for Lethbridge and Victoria, the mean hourly WTG output power per unit area was generally greater during the winter than the summer. The seasonal difference is most apparent at about 0600 hours.

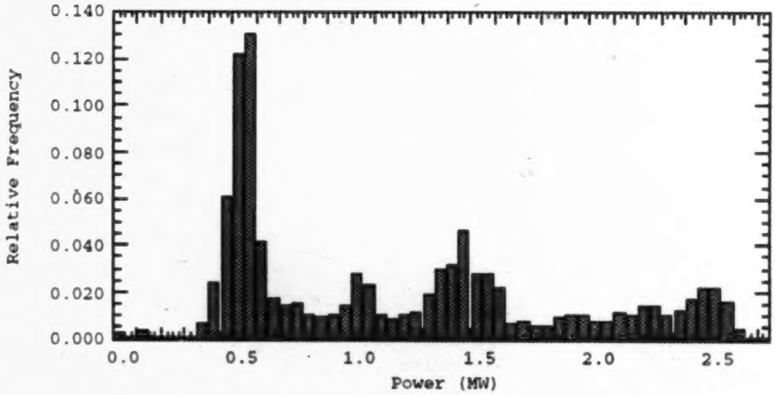
The hourly mean values for the PV module output power are



Total

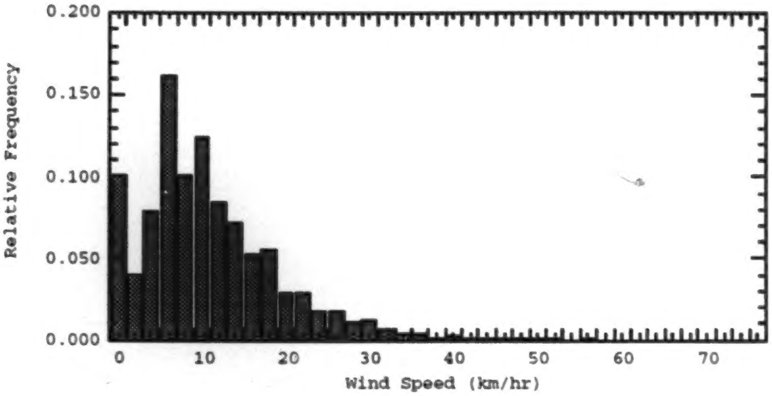


Summer

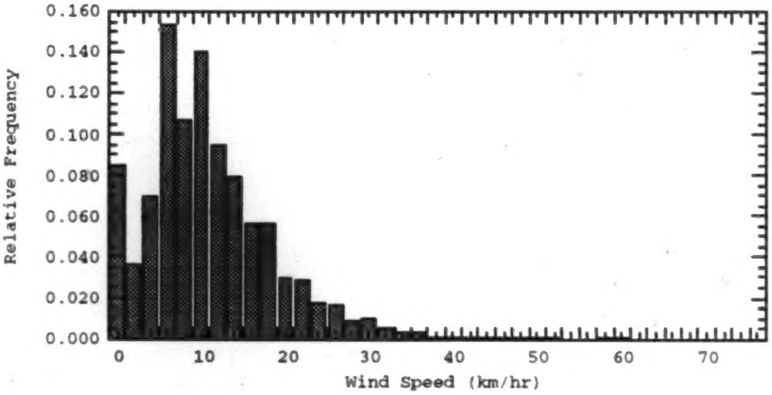


Winter

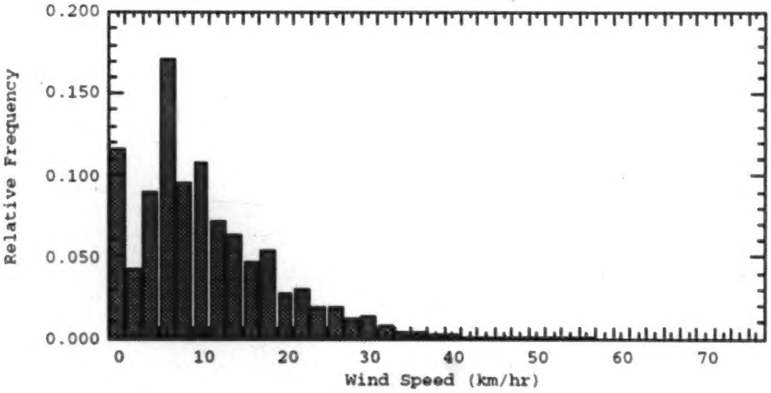
Figure 5.21-1. Delta Load Histograms



Total

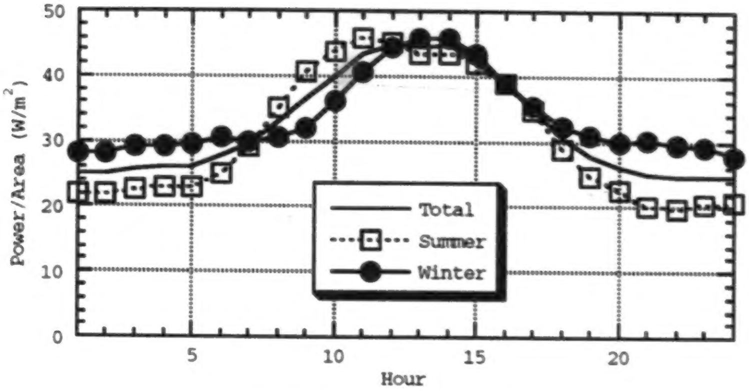


Summer

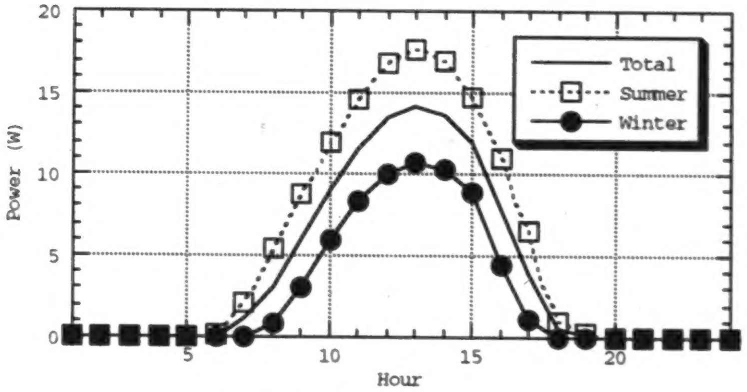


Winter

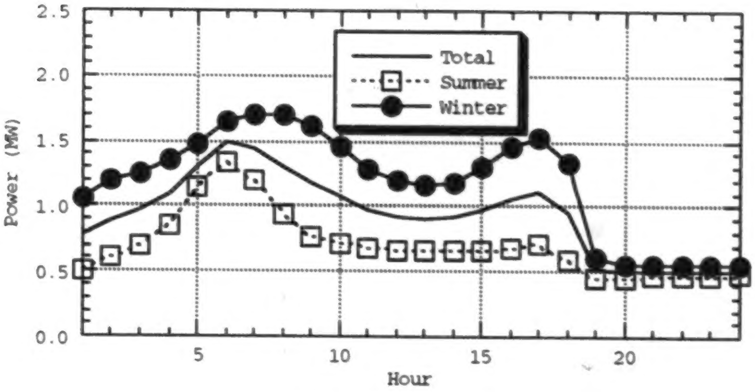
Figure 5.21-2. Delta Wind Histograms



WTG Output Power/Area



PV Module Output Power



Load Demand

Figure 5.21-3. Delta Mean Wind Turbine Generator Output Power/Area, Photovoltaic Module Output Power, and Load Demand

comparable with what had been previously observed elsewhere.

The mean hourly load demand displays two peaks: the larger occurring late in the morning and the smaller at mid-evening. The time at which the larger peak occurs is later for the summer than for the winter.

5.21.6. Results

5.21.6.1. General

The runs for this load were conducted in the same manner as those for Lethbridge and Victoria.

5.21.6.2. WTG Constraint

In order to constrain the optimization algorithm so that any results would include PV modules and batteries, the maximum required WTG area was set to a sufficiently low value. By trial and error, it was determined that a constraint of 30000 m^2 allows this to occur.

5.21.6.3. Modifications to Algorithm

Due to the nature and magnitude of the load, some modifications to the algorithm were necessary.

With the previous loads, an incremental change in, for example, the number of PV modules could result in a significant change in the performance of the system as well as the cost. Most of the mean hourly load demands for those cases were on the order of a few kilowatts. Since this load is considerably larger, with hourly demands of several hundred kilowatts, and since, for example, the rated power of the PV modules is 35 W, an incremental change in the number of modules would be negligible. This was observed during early testing for this load.

For this purpose, an incremental change of 1000 units was used. This quantity was chosen after testing with other values since this load is about 1000 times that for Edmonton Load 1

Similarly, the capacity increments of the auxiliary generator, inverter, and rectifier were also revised from 500 W to 20 kW, starting with 25 kW as the lowest allowed capacity.

5.21.6.3. Results

As an illustration of the type of systems that can result, two cases at full market prices and two cases with reduced prices were examined, using the parameters in Table 5.21-1. The results are given Table 5.21-2. Additionally, the installed costs based on the configurations as well as the equivalent utility line distances are given in Table 5.21-3.

These results show that the configurations are similar to those observed for the previous locations, though at a much larger scale due to the requirements of the load.

5.21.7. Assessment

Based on the results in Tables 5.21-2 and 5.21-3, it can be seen that a stand-alone renewable energy system for a load of this size would be limited in its practicality for a number of reasons.

For example, according to Table 5.21-3, a utility grid would have to be several hundred kilometres away before the cost of the system would be comparable. Such operations are often located close to sources of supplies as well as transportation and markets. This implies that a utility grid would already be present and at distances considerably less than indicated in the table.

Also, the large numbers of components may necessitate additional staff for maintaining the system. The cost estimate used for this investigation did not allow for the additional labour costs, which, in turn, would make the systems given in Table 5.21-2 correspondingly more expensive.

The optimizations for this particular load have shown that the general procedure used previously would be limited when applied to large loads similar to the one examined for this section.

5.22. Comments on Results

5.22.1. WTG Area

It was observed during he course of this investigation that the optimization algorithm was sensitive to changes in the magnitude of the WTG area of less than 0.5 m^2., particularly for Edmonton Load 1 and Lethbridge.

This sensitivity influenced the selection of the upper limit to the WTG area. A slight change in the area could cause the optimization algorithm to produce results which did not include PV modules and/or batteries. Setting this limit to a lower value often prevented this from occurring.

Table 5.21-1. Parameters for Delta

Parameter	Value
Constraints	
$A_{W_{MAX}}$	30000 m^2
$A_{W_{MIN}}$	0 m^2
$N_{S_{MAX}}$	100000
$N_{S_{MIN}}$	0
$N_{B_{MAX}}$	100000
$N_{B_{MIN}}$	0
$P_{G_{MAX}}$	750 kW
$P_{G_{MIN}}$	250 W
Starting Point	
A_W	25000 m^2
N_S	40000
N_B	4000

Table 5.21-2. Results for Delta ($N_{S_{MIN}} = 0$, $N_{B_{MIN}} = 0$)

Case							Results							
Load (MW)	$N_{S_{MIN}}$	$N_{B_{MIN}}$	c_W (\$/m^2)	c_S (\$/mod.)	c_B (\$/A-hr/btty.)	c_F (\$/L)	A_W (m^2)	N_S	N_B	P_G^* (MW)	P_I (MW)	P_R (MW)	f (L/day)	Cost (\$M/yr)
Total Data Set														
Mean	0	0	800	500	2.50	0.45	27006	20000	11000	0.10	0.66	0.52	516	5.55
Mean	0	0	200	125	0.625	0.30	27006	21000	12000	0.04	0.70	0.52	88	1.78
Seasonal Data Set*														
Mean	0	0	800	500	2.50	0.45	30122	63000	10000	0.22	1.00	0.88	2724	8.84
Mean	0	0	200	125	0.625	0.30	30122	70000	12000	0.10	1.12	0.92	375	2.75

*Seasonal fuel consumption average values

Table 5.21-3. Delta Installation Costs and Line Lengths

Case						Results							
Load (MW)	$N_{S_{MIN}}$	$N_{B_{MIN}}$	C_W ($/m^2)	C_S ($/mod.)	C_B ($/A-hr/btty.)	A_W (m^2)	N_S	N_B	P_G^* (MW)	P_I (MW)	P_R (MW)	Installed Cost ($M)	Length (km)
						Total Data Set							
Mean	0	0	800	500	2.50	27006	20000	11000	0.10	0.66	0.52	35.7	1787
Mean	0	0	200	125	0.625	27006	21000	12000	0.04	0.70	0.52	10.1	504
						Seasonal Data Set*							
Mean	0	0	800	500	2.50	30122	63000	10000	0.22	1.00	0.88	60.4	3021
Mean	0	0	200	125	0.625	30122	70000	12000	0.10	1.12	0.92	17.8	888

5.22.2. Objective Function Values

For each value of the WTG area used, an optimum system is obtained, based on continuous values for the numbers of PV modules and batteries. For that system, a value for the objective function is calculated.

In some cases, the values for the objective function based on each WTG area are within a fraction of a percent of each other, though the configurations are different. This can be attributed to the fact that the value of an objective function can be calculated from more than one combination of WTG area, PV modules, and batteries.

An example of this is one Edmonton Load 1 run for which the WTG areas are 27.0 m^2 and 26.0 m^2. The configuration based on the former area required 33.9 PV modules, 12 batteries, and a 98.3 W auxiliary generator, with the objective function value being $3878. The one based on 26.0 m^2 required 38.4 PV modules, 12 batteries, and a 354.8 W auxiliary generator, yielding a value of $3907.

This indicates that some cases may have more than one solution for the same value of the objective function, though they may not necessarily have similar configurations. Such situations can arise in actual designs with the final selection often made at the designer's discretion.

5.22.3. Load and Location

A number of loads at different locations were examined for this investigation, with each load and each site having its own characteristics.

This affected the manner in which the optimization was carried out. Each load at each site required its own set of constraints and starting point and each case examined yielded its own set of results.

The weather data was used in selecting what type of renewable energy source should be used. Specifically, the distribution of the wind speeds in the histograms were used to select the type of WTG.

Indirectly, the weather data was also used in setting some constraints. The times for which (5.6.4-1) had to be met was determined from the output power of the PV module.

Examining the load data gave an indication on what upper limit should be placed on the auxiliary generator capacity as well as possibly giving an indication as to how many PV modules and batteries may be required for the starting point.

An example of this can be seen for Edmonton Load 1 and Edmonton Load 2, each load having different characteristics.

This indicates that each load at each location should be handled individually and that the data used should be examined beforehand in order to establish appropriate constraints and starting points.

5.22.4. Constraints and Starting Points

The constraints and starting points used for these optimizations were estimated from the available data with the purpose of causing the algorithm to produce results that required combinations of WTG's, PV modules, and batteries.

The results obtained indicated that the upper limit on the required WTG area was critical, particularly when the optimization began at a higher starting point. The sensitivity of the results to the WTG area mentioned in 5.22.1. was also affected by this limit.

If the starting point for the numbers of PV modules and batteries was low, the optimization algorithm usually produced systems that required large WTG areas without any modules or batteries.

Most of the optimization results that included PV modules and batteries showed that more modules than batteries were required. Often there was a ratio of 4 or 5 modules required for each battery. This characteristic was used in the selection of the starting points. When equal numbers of modules and batteries were chosen, the resulting configurations usually consisted only of WTG's and the auxiliary generator. Often, the algorithm starting with such a point would eliminate the batteries. Subsequent runs resulted in the PV modules being eliminated thereafter.

From this, it can be seen that the selection of appropriate constraints and starting points is required for the optimization algorithm to produce a configuration which required PV modules and batteries. This can be determined, in part by examining the load demand and weather data, as described in 5.22.3.

5.23. Evaluation of Method and Recommendations

An optimization algorithm based on the Luus-Jaakola direct search method was developed in this investigation. This algorithm was applied to several loads using weather data for the sites at which these loads were located.

For this investigation, hourly mean values for the WTG output power per unit area, PV module output power, and load demand were utilized for the optimization. Some of the results were tested with an approximate simulation. There were indications that the optimization results on which these simulations were based were feasible and could provide the basis for an actual design.

The method as originally formulated as the sole basis for a design is not recommended at this time. To knowingly use it with the deficiencies which exist in it would be poor practice. This could lead to a defective design, resulting in a system which potentially could have poor performance.

Further development would be necessary in order for this method to be properly utilized. Some of shortcomings in the method as formulated were already noted. Examples of these shortcomings were problems with the capacity of the auxiliary generator and maximum battery charge current during the evening. There difficulties were resolved by modifying of the optimization method to allow for a larger auxiliary generator and variable battery charge currents.

It is recommended that some of the suggestions for future work given in 5.22. be investigated as they address some of these shortcomings, especially with regard to the control of battery charging. Also, a controller could be used to co-ordinate the dispatch of the different energy sources.

In addition, changing the method by which the battery capacity is determined to allow for longer time periods (such as 48 or 72 hours of operation instead of the 24 hours considered for this investigation) would increase the likelihood that sufficient battery charge would be available at any given time.

Most of the results were based on mean values for the load demand, wind turbine generator power/area, and photovoltaic module power. Since the means do not necessarily account for short-term variations, optimizations based on, for example, the mean plus a standard deviation for each quantity could be investigated. The results from these optimizations can then be tested in a simulation to determine if renewable energy systems based on them could meet the load demand more often.

It is also recommended that results obtained by using a modified optimization method be tested in a simulation covering a period of at least one full year to account for seasonal variations. The performance of that system would provide the basis for any additional optimization runs which may be required. The constraints and starting point for these runs would be adjusted based on the behaviour of that system and the judgement and experience of the designer.

One of the advantages of the method used for this investigation is that the manner in which it was formulated allows for the computer code used for it to be quickly modified if necessary. The system operations described by the model are integrated into the algorithm as distinct constraints, unlike what might be the case with other optimization methods, such as penalty functions described in (5.4.3-2). For such methods, the constraints are included in the objective function, often making any reformulation due to changes in constraints difficult.

By comparison, the algorithm used for this investigation considerably simpler, which was beneficial when checking if specific constraints were being violated during an optimization run. Diagnostic commands could be easily inserted into the computer code without having to alter any of the algorithm's commands. Constraints could be readily changed without the necessity of re-deriving any functions.

The results of this investigation indicate that this method has potential as a means of optimizing a stand-alone hybrid renewable energy system. It is recommended that development work on this method continue.

5.24. Suggested Future Work

5.24.1. Charge Control

During the examination of the simulations for Edmonton Load 1, one of the modifications that were made was to change the rate at which the batteries were charged towards the end of the day. One possible modification to the algorithm would be a set of constraints which will allow for a variable charge rate in order that the operating parameters of the battery not be violated, or to allow for more supplementary operation of the auxiliary generator.

This modification will require the addition of a controller, along with the formulation of the appropriate control algorithm and associated constraints and costs.

5.24.2. Design Parameters

For this investigation, a set of specific operating characteristics were used for the components. Future work should include the consideration of different components, particularly for the PV module and batteries to determine what types of configurations would result.

In addition, an examination of different costs for these components as well as the effects of cost reductions on the configuration designs should be undertaken. The results obtained from the optimization algorithm showed that large cost reductions have significant effects on the type of configurations produced. Future work could include the effects of price reductions due to, for example, bulk purchases.

5.24.3. Large Loads

One of the difficulties in applying the optimization algorithm to the Delta region load was the large numbers of components required for the configurations that were specified. For the other loads, changing the number of, for example, PV modules by one often had a significant effect on the cost of the system in question. For the last load, this would have had a negligible effect not only on the cost but also on the performance of the system.

Any future work should consider this aspect, particularly with respect to the amount by which the components are changed during optimization. In addition, the sensitivity of the algorithm to scaling of loads should also be investigated.

5.24.4. System Controller

As mentioned in 5.1., a controller for managing the dispatch of the different energy sources will be required. Future work in which the model includes such a controller is recommended.

5.24.5. Additional Loads and Locations

5.24.5.1. General

During the course of this investigation, 5 loads at 4 different geographical locations were examined. These loads were for agricultural applications and, based on the data obtained, assumed to be AC.

Future work with this algorithm could include:

- its application to different loads, such as those for industrial facilities,

- the examination of loads at more locations, particularly with different climatic conditions, such as those further inland on the Canadian prairies or in the vicinity of the Great Lakes,

- loads which combine AC and DC components, and

- loads with essential and non-essential components, allowing for shedding.

5.24.5.2. Industrial Loads

The loads examined for this investigation were for agricultural applications. Their respective load demands varied significantly throughout the day. On the other hand, industrial facilities such as oil refineries and machine shops likely have load patterns and duty cycles different than those for a farm, placing a different set of requirements on their power sources.

5.24.5.3. Different Geographical Locations

The loads examined for this investigation were located in B. C. and Alberta. Sites further inland, such as in Saskatchewan, have different climatic conditions, which may have an effect on the results produced by the optimization algorithm.

The loads for Victoria and Delta were at coastal locations with climates milder than those at Edmonton and Lethbridge. Locations near large bodies of water may be of interest due to resulting climatic conditions.

5.24.5.4. AC and DC Loads

The loads examined for this investigation were assumed to be AC. Optimizations which consider both AC and DC loads may result in different renewable energy configurations, particularly with respect to the number of PV modules and batteries which might be required.

This will likely have an effect on the type of controller that will be needed to operate the system.

5.24.5.5. Load Shedding

In load shedding, when insufficient power is present for meeting the load demand, parts of it can be temporarily disconnected. These portions of the load are not essential and their operation is optional, depending upon the availability of power.

This investigation assumed that the mean load demand was calculated for the entire load for a given hour. Future work could include revising the model so that such operations could be accommodated, thus reducing the cost of a renewable energy system.

5.24.5. Inclination Angle

For this investigation, he inclination of the PV modules was set to the local latitude. Future work should include changing the angle with the seasons in order to increase the module output power.

5.24.6. Battery Capacity

A 24-hour cycle was used for this investigation. Future work should include changing the method in order that the batteries could provide power for longer time periods, such as 48 or 72 hours.

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APPENDIX A

WEATHER DATA FORMAT

1.0. DATA FORMAT

The meteorological data used in this investigation were of the following format.

The data for each day consisted of a single string of alphanumeric characters, as given in Table A-1 [1]. Each element value block consisted of 7 characters, as given in Tables A-2 and A-3 [2], [3]. For missing data, the element value block for the given time interval was given as -99999M.

When necessary, the data received from Environment Canada was converted to this format [4].

2.0. DATA UNITS

2.1. Hourly Dry Bulb Temperature

The values for the hourly dry bulb temperature were given in increments of 0.1° C [5] and were measured at the top of each local standard hour [2].

2.2. Hourly Wind Speed

The values for the hourly wind speed were given in integer increments of km/hr [5] and were measured at the top of each local standard hour [2]. The values were read directly in knots and then converted into equivalent values in km/hr. These do not necessarily account for variations in the wind speed throughout the hour [6]. The integer values resulted from roundoff.

The values were measured at an elevation of 10 m above local elevation [7].

2.3. Hourly Radiation

The values for the hourly global solar radiation and hourly sky radiation were cumulative values for the energy received during the respective hours were given in increments of kJ/m^2 [8] and were measured at the top of the local solar hour [2]. According to [9], the times of radiation measurements were ahead of the times for the other measurements.

2.4. Snow Cover

Snow cover was indicated as a flag in the radiation values. The values that this flag could take are given in Table A-3 [3].

Table A-1. Data String Format

Characters	Description
001 - 007	station identification
008 - 011	year
012 - 013	month
014 - 015	day
016 - 018	meteorological element
019 - 186	element values (24 blocks of 7 characters)

Format described in [1].

Table A-2. Data Value Format

Characters	Description
1	value sign
2 - 6	value
7	flag

Format described in [1], [2].

Table A-3. Flag Values

Flag	Description
U	Unknown snow cover
V	No snow cover
W	Snow cover
X	Unknown snow cover (estimated)
Y	No snow cover (estimated)
Z	Snow cover (estimated)

Descriptions found in [3].

3.0. DATA CONVERSION

3.1. General

The meteorological data was converted from the form presented in the Environment Canada data files into its final form by means of a program written by the author using Symantec® *C++ 8.1*.

3.2. Time

The values for the year, month, and day of each data string were read directly from the files. The daily hours were obtained when each meteorological element data block was read. The cumulative hours for each data string were also determined.

The variation of each meteorological element throughout each time interval was not known. Since there is usually a significant difference between local apparent time and local standard time (as explained in references such as [10]), it was assumed that the temperatures and wind speeds at the top of each local apparent hour (when the radiation values were measured) were identical to those given in the original data files.

3.3. Hourly Dry Bulb Temperature

The values for the hourly dry bulb temperature were obtained by dividing the values given in the data files by 10.

3.4. Hourly Wind Speed

The values for the hourly wind speed were obtained by converting the given integer values into floating point variables.

3.5. Hourly Radiation

The values for hourly radiation were cumulative values for the energy received during the respective hours. These were converted into irradiances by dividing these values by 3600 to convert from J/m^2 to W/m^2.

3.6. Missing Values

Those data points with values equal to -99999M (described in 1.0) were replaced by the averages of the remaining values of that quantity for the same day and time [11]. For example, if, for a given year, no value for the temperature at 0800 hours on March 14 existed, the average for all other available temperature values at 0800 on March 14 was used.

This necessitated two passes in order to complete the data conversion.

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APPENDIX B

COMPUTING SYSTEM DATA

Data on the computer system used for this investigation are given in Table B-1. Questions concerning the computer code used for this investigation should be directed to the author.

Table B-1. Computer System

Item	Description
Computer	Apple® Power Macintosh 7100/66 (upgraded with Sonnet Crescendo G3 card)
Operating system	MacOS™ 8.6
Memory	48 MB RAM/64 MB virtual memory
Languages	Symantec® *C++ 8.1* (weather data conversion) *IDL® 5.1+*, (data processing, optimization algorithm)
Typical execution times	1200 - 1800 s (total data set) 2100 - 3700 s (seasonal data set)

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